

TECHNICAL EVALUATION OF ALTERNATIVE NO_x CONTROL TECHNOLOGIES

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INTERMOUNTAIN POWER PROJECT
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EXECUTIVE SUMMARY

KVB was engaged by the Intermountain Power Project (IPP) to investigate the technical aspects of five NOx reduction techniques with respect to application to IPP's planned coal-fired boilers. Although IPP received permits to construct in 1980, the five techniques were selected as part of a review of IPP emission limitations being conducted by the State of Utah Department of Health (DOH). The following are the alternate techniques selected for review by the DOH:

- Selective catalytic reduction (SCR)
- Thermal DeNOx®
- Overfire air ports (OFA)
- Lower excess combustion air
- Decreased plan heat release through boiler derating

NOx CONTROL AT IPP

The NOx (nitric oxide and nitrogen dioxide) formed in coal-fired utility boilers is derived partly from nitrogen in the air, but predominantly from nitrogen in the coal. The most effective ways of minimizing NOx formation are those which cause the pulverized coal to be heated in the absence of air; these methods drive off the nitrogen in the fuel to form N₂ rather than NOx.

IPP's design for low NOx will achieve NOx emissions no greater than 0.550 lb/MBtu. That emission level is equal to or better than the emission limit imposed as a result of the Best Available Control Technology (BACT) reviews conducted by state and federal agencies issuing permits for IPP. The IPP design currently includes the use of low-NOx, low-excess-air burners, and a low furnace heat release rate.

ALTERNATE NOx CONTROL

The alternate NOx reduction techniques selected for consideration by the Utah DOH are discussed below.

1. Selective Catalytic Reduction (SCR)

This technique uses ammonia (NH_3) to destroy NOx with the aid of a solid catalyst. The process has been experimentally demonstrated in Japan on a coal-fired boiler in which a hot-side precipitator was used to remove ash before the flue gases entered the catalytic reactor. This experience is not applicable to IPP, where a fabric filter baghouse, located downstream of the potential location of an SCR unit, is to be used to ensure compliance with stringent particulate emission regulations. Furthermore, the Utah coals to be used by IPP contain catalyst "poisons" which could render the SCR catalyst ineffective. The SCR process has not been adequately developed for application to a large coal-fired plant such as IPP Units 1 and 2. Thus there is no certainty that the SCR process, if retrofitted at IPP, could yield reliable continuous reductions in NOx emissions.

2. Thermal DeNOx

This process also uses ammonia to destroy NOx, but is carried out at a higher temperature so that a catalyst is not needed. Thermal DeNOx has never been demonstrated to be effective on a coal-fired boiler, and therefore is not appropriate as a technology for establishing emission limits for IPP.

3. Overfire Air Ports

This technique is believed to offer little or no NOx reduction potential for IPP without creating adverse side effects such as slagging, boiler tube wastage, and increase of excess air requirements. The low-NOx burners incorporated into the present IPP design are capable of yielding low NOx without adverse side effects. Retrofitting overfire air ports at IPP will not necessarily reduce emissions below 0.550 lb/MBtu, and in fact, the use of these ports may cause NOx emissions to increase.

4. Low Excess Combustion Air

This technique is already a part of the IPP design and cannot be carried further without causing unacceptable side effects such as slagging, reduced steam temperature, and loss of boiler efficiency.

5. Decreased Plan Heat Release Through Boiler Derating

This involves abandoning use of some of the design capacity of the generating units. This technique cannot predictably yield NOx reductions and, in any case, cannot be considered new technology developed since the IPP permits were issued.

KVB's conclusion from this study is that the present NOx control design for IPP includes all technology which has demonstrated achievable reductions in emissions for large coal-fired boilers. This design should therefore be considered Best Available Control Technology (BACT) for IPP.

SECTION 1.0

INTRODUCTION

The Intermountain Power Agency, a political subdivision of the state of Utah, is building, near Lynndl, Utah, a power plant to be fired with Utah bituminous coal. This Intermountain Power Project (IPP) is located on a site which was chosen by a task force created by the governor of the state of Utah. The task force included representatives of environmental and industrial interest groups, the state of Utah, and the federal government.

Permits issued by both the State of Utah and the U.S. EPA established stringent limits on the IPP boilers' emissions of sulfur oxides, particulate matter, and nitrogen oxides. These limits were determined according to the capabilities of Best Available Control Technology as defined in the proceedings leading to the issuance of the permits in 1980.

The State of Utah Department of Health recently requested that the IPP provide additional information on the following five NOx reduction techniques in (Refs. 1 and 2):

1. Selective catalytic reduction (SCR)
2. Thermal DeNOx®
3. Overfire air ports
4. Lower excess combustion air
5. Decreased plan heat release through boiler derating

These five techniques were to be investigated from both the cost impact to IPP and technical standpoints. KVB was engaged by IPP to investigate the technical aspects of these techniques with relevance to the design of Units 1 and 2 at the Lynndyl site.

The objective of this report is to present KVB's findings on the technical aspects of applying the five techniques to IPP. A separate report by Black and Veatch, the architect/engineer firm for IPP, addresses the potential cost impacts of imposing the five techniques on IPP at this time.

Section 2 of this report gives some background on NOx control for utility boilers. Section 3 explains the IPP design for NOx control and presents some of the background leading to the EPA and DOH permits. In Section 4, the five specific techniques requested by the Utah DOH for review are discussed, and KVB's conclusions are listed in Section 5.

SECTION 2.0

NOX CONTROL FOR UTILITY BOILERS - BACKGROUND INFORMATION

This section explains how NOx is formed in a coal-fired boiler, describes methods for controlling NOx emissions, and outlines the limitations and adverse effects of those NOx emission control methods.

The control of nitrogen oxide (NOx) emissions from coal-fired utility boilers can be effected by either controlling the formation of NOx during the combustion process or by destroying the NOx in the flue gases after it has been formed. Combustion control of NOx has been studied on a small scale and implemented on a full scale basis both in the U.S. and abroad for the past 15 years. Destruction of NOx in the flue gases, or post-combustion NOx control, has been studied on a pilot scale for a number of years abroad with more recent studies being performed in the United States. Full-scale application of post-combustion control on coal has only recently been studied on an experimental demonstration basis in Japan.

This section provides background information on the NOx formation and destruction mechanisms and the limiting control factors for combustion and post-combustion control techniques. Supplemental information is provided in in Section 4.0, as well as in Appendices A, B, and C.

2.1 COMBUSTION CONTROL OF NOx

During combustion of fossil fuels used in utility boilers, air is combined with the fuel to release energy to generate the steam. The products of combustion of these fossil fuels are primarily carbon dioxide (CO₂) and water vapor (H₂O). Nitrogen oxides comprise about 0.04 percent of the combustion products or only a trace amount of the total products. The exact amount of these oxides produced is dependent on the fuel type as well as boiler/burner design related factors. This section provides general information relative to NOx formation from coal combustion, combustion control techniques, and the adverse side effects resulting from combustion NOx control.

2.1.1 NOx Formation

Unlike particulate and sulfur oxide emissions from coal-fired boilers, NOx emissions can be significantly affected by modification of the combustion process. This unique characteristic results from the fact that the quality of combustion and subsequent NOx formation are functions of the three "T's" of combustion: time, temperature, and turbulence in the primary flame zone. Modifications can be made to these parameters that effectively liberate the available thermal energy while at the same time significantly altering the trace products of combustion--namely NOx.

The NOx generated from a utility boiler, during the combustion process, consists almost entirely of two species: nitric oxide (NO) and nitrogen dioxide (NO₂), with NO comprising about 95 percent of the total NOx. Formation of NOx in a coal-fired utility boiler results from two mechanisms: thermal fixation of atmospheric nitrogen (thermal NOx) and conversion of nitrogen contained in the fuel (fuel NOx), both of which are described below. The NOx formed in coal-fired utility boilers is partially thermal NOx, but is predominantly fuel NOx, consequently at coal-fired plants "fuel NOx" plays a major role in the formation of the total NOx. Extensive research efforts have been undertaken to better understand both thermal NOx formation and fuel NOx formation from coal firing. The following paragraphs briefly describe the basics of these formation mechanisms; a more thorough discussion can be found in Appendix A.

Thermal NOx

During combustion, nitrogen oxides are formed by high temperature thermal fixation of N₂. Nitric oxide (NO) is the major product, even though NO₂ is thermodynamically favored at lower temperatures. The residence time in most boilers is too short for significant amounts of NO to be oxidized to NO₂.

Experiments at atmospheric pressure indicate that under certain conditions, the amount of NO formed in heated N₂, O₂, and air mixtures can be expressed as (Ref. 3):

$$[\text{NO}] = k_1 \exp(-k_2/T) [\text{N}_2] [\text{O}_2]^{1/2} t \quad (2-1)$$

where [] = mole fraction
k₁, k₂ = constants
T = temperature
t = time.

Although this expression does not adequately describe NO formation in a turbulent flame, it points out several features of thermal NO_x formation. It reflects the strong dependence of NO formation on temperature. It also shows that NO formation is directly proportional to the square root of oxygen concentration.

NO formation in boilers begins with the onset of combustion as turbulent eddies or pockets of air-fuel gaseous mixtures expand into the furnace. The amount of NO formed depends on subsequent temperature and concentration time history of the individual gaseous pockets. Temperature decay of the gas products results primarily from mixing with combustion air and recirculated cooler bulk gases. As the temperature decreases, the NO formation rate falls off and essentially ceases when the temperature drops below 3000°F.

Natural gas combustion in utility boilers is very rapid and generally occurs in the region of the burner throat. The peak combustion temperature in this region is near the adiabatic flame temperature, or theoretical temperature with no heat loss. NO formation for natural gas fired boilers can, consequently, be substantially diminished by reducing the peak flame temperature and/or decreasing the oxygen availability in this region of intense heat release. Oil and coal combustion is less rapid than gas and occurs primarily in the bulk gas region (furnace) away from the burner throat. This is partially due to the fact that the fuel must first be vaporized or volatilized before combustion can be completed. As a result, oil and coal peak combustion temperatures do not approach the adiabatic flame temperature since the products lose some energy by radiation before combustion is complete. As a consequence of this, thermal NO_x formation from coal-fired boilers constitutes only a small percentage of the total NO_x formed. NO_x reduction techniques that are effective for thermal NO_x and may be used for gas-fired boilers are consequently relatively ineffective on coal-fired utility boilers.

Fuel NOx

The predominant mechanisms for NOx formation from coal-fired boilers is conversion of the fuel-bound nitrogen. This accounts for 60 to 80 percent of the NOx formed. Fuel-bound nitrogen occurs in coal and petroleum fuels. However, the nitrogen-containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation (Ref. 4). Therefore fuel NOx is of importance primarily in residual oil and coal firing. The nitrogen compounds found in petroleum include pyrroles, indoles, isoquinolines, acridines, and porphyrins. Although the molecular structure of coals in general has not been defined with certainty, it is believed that coal-bound nitrogen also occurs in aromatic ring structures such as pyridine, picoline, quinoline, and nicotine (Ref. 4).

The nitrogen content of residual oil varies from 0.1 to 0.5 percent. Nitrogen content of most U.S. coals lies in the 0.5 to 2 percent range (Ref. 5). Thus "fuel NOx" is a primary concern of coal combustion, controlling 60 to 80 percent of the NOx formed. The chemical form of the nitrogen in the fuel is one of the variables that determines its contribution to the fuel NOx. Since the exact forms and their relationship to NOx are not presently known, this contribution is not quantifiable. The fuel NOx also depends on other coal variables such as heating value, moisture and volatiles content in complex and unquantified relationships. The fuel NOx cannot, therefore, be accurately predicted from the nitrogen content of the coal.

Although the precise mechanism by which fuel nitrogen in coal is converted to NOx is not understood, certain aspects are clear. In a large pulverized coal-fired utility boiler, the coal particles are conveyed by an air stream into the hot combustion chamber, where they are heated at a rate in excess of 10000°F/sec. Almost immediately, volatile species containing some of the coal-bound nitrogen vaporize and burn homogeneously, rapidly (approx. 10 milliseconds), and probably detached from the original coal particle. Combustion of the remaining solid char is heterogeneous and much slower (approx. 300 milliseconds). Nitric oxide can be produced from either the volatile or char fraction of the coal.

Based on experimental and modeling studies, it is believed that 60 to 80 percent of the fuel NOx results from volatile nitrogen oxidation. Conversion of char nitrogen to NO is generally lower, by a factor of two or

three, than conversion of volatile coal nitrogen, and is also relatively insensitive to load or overall stoichiometry.

Regardless of the precise mechanism of fuel NO_x formation, several general trends are evident. Fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment, as shown in Figure 2-1. Oxidation of the char nitrogen is relatively insensitive to fuel/air changes, but volatile NO formation is strongly affected by fuel/air ratio changes. Thermal nitrogen is also affected by the fuel/air ratio. The effect of fuel/air ratio on the relative contribution of each form of NO (thermal, char, and volatiles) can be seen in Figure 2-2.

In contrast to thermal NO_x, fuel NO_x production is relatively insensitive to small changes in combustion zone temperature (Ref. 8). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage conversion. Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current boiler systems.

Fuel NO_x emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal volatilization will dramatically increase volatile nitrogen conversion and increase fuel NO_x. In contrast, char NO formation is only weakly dependent on initial mixing.

2.1.2 NO_x Control Methods

The primary mechanisms used to reduce NO_x from utility boilers can theoretically involve three tactics:

1. Decreasing the mixing between the fuel and air while the combustion products are reacting.
2. Decreasing the oxygen content during initial combustion.
3. Decreasing the temperature of the fuel and air.

These mechanisms have varying degrees of effectiveness depending on the fuel. All of these mechanisms are effective when attempting to reduce "thermal NO_x" on fuels such as gas and oil. Since coal-fuel NO_x formation is predominantly from fuel NO_x formation, as explained previously, temperature

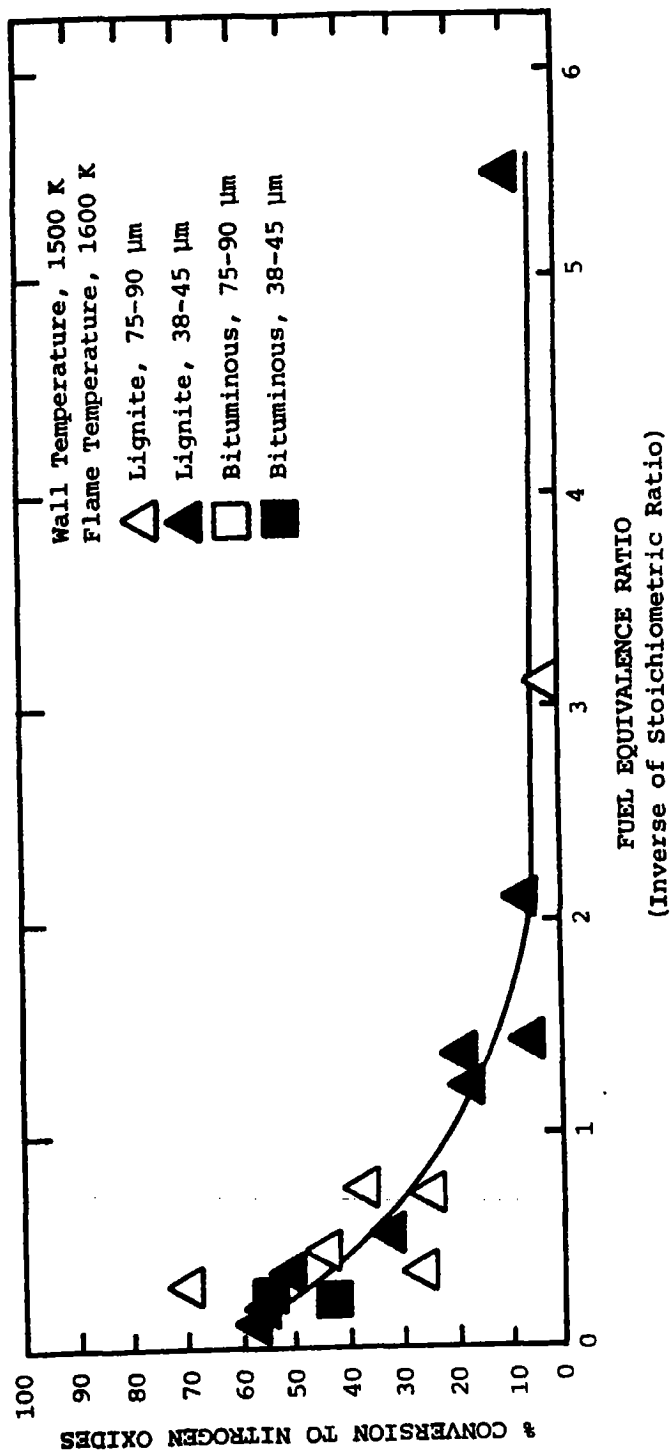


Figure 2-1. Conversion of nitrogen in coal to NOx (Ref. 6).

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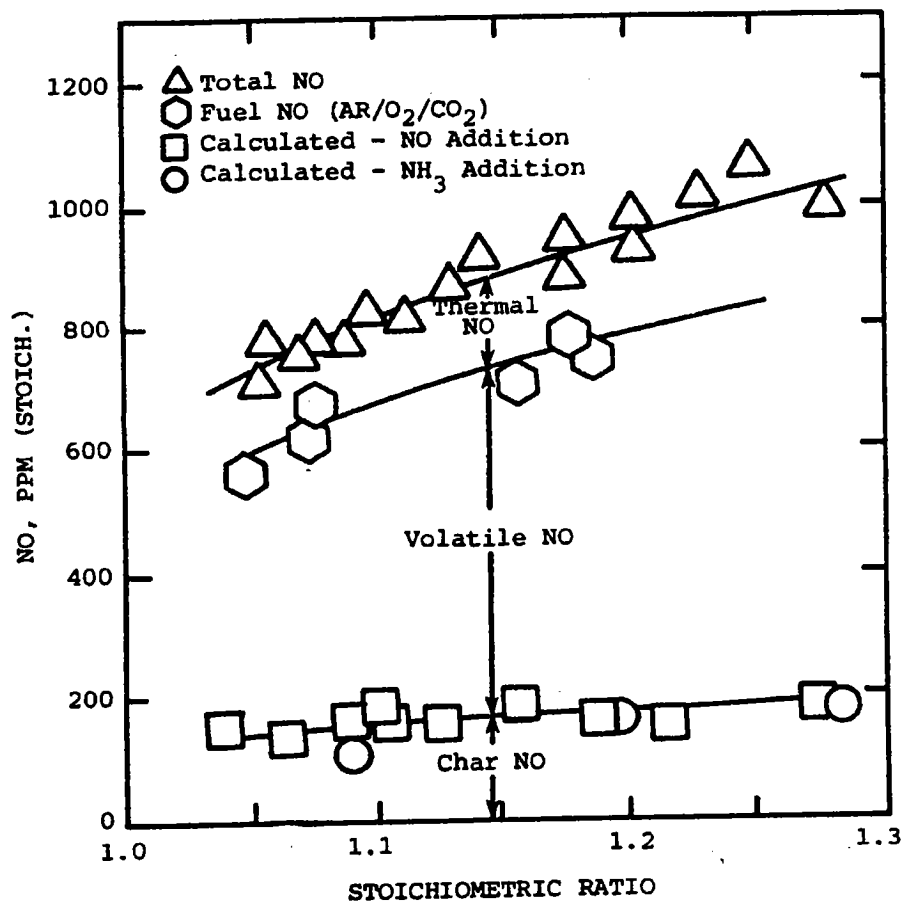


Figure 2-2. Sources of NO_x emissions in turbulent-diffusion pulverized-coal flames. Wall-fired simulation: Western Kentucky coal (Ref. 7).

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reductions are relatively ineffective. Consequently, decreasing the temperature of the fuel and air has only a secondary effect on controlling "fuel NOx." Therefore, controlling the mixing or turbulence and the stoichiometry or fuel-air ratio during combustion are the effective NOx reduction techniques on coal-fired boilers.

As a consequence of the fact that reduction of thermal NOx is not of as significant importance on coal-fired boilers, an entire class of techniques normally used on gas- and oil-fired boilers has little effectiveness with coal. These include the reduction of combustion air preheat and the introduction of diluents such as recirculated flue gas or water into the combustion air. Full-scale tests on coal-fired boilers have found these to be ineffective methods (Ref. 9).

The primary control mechanisms left for coal firing are then tailoring the mixing of fuel and air during the volatilization and pyrolysis of the nitrogen in the coal coupled with controlling the stoichiometry of the initial combustion zone. The basic technique of off-stoichiometric or staged combustion has evolved over the years to a high degree of sophistication. This technique, is the primary means of controlling fuel NOx from coal-fired boilers. Early in the search for effective methods of implementing this technique, overfire air was used. This technique is explained thoroughly in Section 4.3. Concerns about adverse side effects from this method, however, led boiler manufacturers to develop low-NOx burners to accomplish localized off-stoichiometric combustion.

These new low-NOx burner designs ensure locally fuel-rich conditions during devolatilization, which promote reduction of devolatilized nitrogen to N_2 . Two-stage combustion produces overall fuel-rich conditions during the first one to two seconds and promotes the reduction of NO to N_2 through reburning reactions. High combustion air preheat may also be desirable because it promotes more complete nitrogen devolatilization in the fuel-rich initial combustion stage. This more complete volatilization leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage where more NOx could potentially be formed.

Low NOx burners (LNBs) which are designed for utility boilers control the NOx by reducing flame turbulence, delaying fuel/air mixing, and establishing fuel-rich zones where partial combustion takes place initially. This

represents a departure from the usual burner design procedures which promote high turbulence, high intensity, and rapid complete combustion flames. The longer, less intense flames produced with LNBs result in lower flame temperatures which reduces secondary thermal NOx generation. Of even greater importance, the reduced availability of oxygen in the initial combustion zone inhibits fuel NOx conversion. Thus, the fuel NOx and the small amount of thermal NOx formed from coal combustion are controlled by these new LNBs.

This tailoring of the flame necessitates increased furnace sizes in the burner zone to accommodate the longer flames as well as provide the proper thermal environment to minimize NOx formation. The combined furnace and burner provide the lowest combustion formed NOx while maintaining proper steaming conditions. The integrated designs (burner/boiler) provide low-NOx emissions at minimum excess oxygen levels while providing margin for normal day-to-day variations in operation. The built-in margins are necessary to minimize the impact of certain adverse side effects that accompany off-stoichiometric operation.

2.1.3 Adverse Impacts of NOx Control

It is important to know all contributing factors in a pulverized coal-fired boiler in order to understand how low-NOx combustion techniques and combustion conditions can have severe adverse effects on coal-fired boilers--e.g., they can cause corrosion, fouling, and/or slagging. These potential problems are strongly related to coal ash characteristics and are also influenced by other operating conditions. A detailed discussion of these potential adverse side effects is given in Appendix B. In addition to these side effects, other equipment and coal-related variables place limitations on the NOx reductions achievable with a given boiler/burner configuration and a given coal. Since the NOx control device is also the combustion chamber or furnace, the variables that affect and are affected by the combustion process also influence NOx emissions. Variables that influence NOx emissions include but are not limited to: coal property variations, slagging tendency, and equipment deterioration. Each variable is discussed below.

Coal Property Variations

It is well known that one of the most uncertain aspects of pulverized coal firing is the ability to always provide the type coal for which the combustion system and boiler were designed. This is true even when all of the

coal comes from the same mine. As a result, most boilers burn a fairly wide range of coals during their lifetime. Even if a coal's fuel nitrogen content does not change, but the ash and/or moisture content changes, there will be variations in NOx formation because either more or less coal would have to be burned to obtain the same boiler steam flow.

Slagging Tendency

Slagging is a common problem in pulverized coal fired boilers, the severity of which depends on the coal properties and operation of the unit. Slagging results in higher NOx emissions for two reasons. First, slagging reduces the heat transfer in the furnace zone and thus results in a hotter burner combustion zone, which increases NOx formation. Second, higher excess oxygen levels are required in order to help eliminate the slagging conditions, which also increases the NOx formation.

Equipment Deterioration

Normal burner and boiler related equipment deterioration will always occur with time and it is seldom obvious where the problem lies. Only through detailed testing and investigation are such problems usually found and corrected. During such periods of investigation, it may be necessary to maintain higher than normal excess oxygen levels to compensate for such conditions. Under these conditions, the NOx formation may be unavoidably higher than under normal conditions.

With these concerns about the adverse impacts of NOx control, limitations are placed on the degree to which certain techniques can be used. Based on these and other considerations, EPA has defined, in Reference 10, that the accepted NOx control method is staged or off-stoichiometric combustion, low excess air operation, and reduced heat release rate in the furnace. The limitations of these methods are discussed below.

Staged combustion is limited by incomplete combustion and excessive flame length. The former results in increased carbon carryover in the flue gas which leads to decreased efficiency and increased likelihood of baghouse and flue gas duct fires. Excessive flame length could result in reducing atmospheres near the furnace wall due to a wall-flame impingement condition which promotes slagging and hence furnace wall corrosion. Both slagging and corrosion affect the availability and reliability of the boiler. Low excess air operation has its limitations since slagging and insufficient carbon

burnout will occur below certain excess oxygen levels. Heat release rate is limited by steam temperatures. If the heat release rate is too low., i.e., the furnace is excessively large, too much heat is transferred in the furnace and the steam temperature going to the turbine cannot be maintained at design levels without using significantly higher excess air levels or some other means of control. This necessitates an increase in the amount of fuel which must be burned, which will in turn result in an increase in NO_x, SO₂, and particulate matter.

Evolution of the second generation boiler/burner designs has incorporated staged combustion, low excess air, and reduced heat release rate per unit heat-absorbing area. The systems are designed to be integrated such that the potential for slagging, fouling, and corrosion are minimized. Generally speaking, superimposing additional combustion control techniques on this integrated system will increase the potential for adverse side effects. In addition, the effectiveness of the individual combustion control techniques is not additive. In fact, the effectiveness of added techniques diminishes rapidly such that the combined effect can be indistinguishable from the individual control effectiveness. Such is the case with superimposing overfire air ports on a boiler designed for low-NO_x burners.

2.2 POST-COMBUSTION CONTROL

After NO_x is formed in the completed combustion process, it can be destroyed through chemical reactions promoted by the introduction of ammonia. This is generally referred to as "post-combustion" NO_x destruction. The basis for these destruction mechanisms are briefly discussed in this section. More extensive descriptions are provided in Sections 4.1 and 4.2, and in Appendix C.

2.2.1 NO_x Destruction

There are no naturally occurring destruction mechanisms in the boiler backpass system that promote destruction of the combustion formed NO_x. Introduction of certain compounds into the flue gases can however cause the NO to react to form nitrogen and water vapor. Two basic mechanisms have been used to promote this reduction: thermal and catalytic destruction. These are commonly referred to as Thermal DeNO_x, which is a trade name of an Exxon process, and selective catalytic reduction (SCR) which is a generic process

which originated in Japan. Both processes use ammonia as the destruction agent.

The Thermal DeNOx process was patented by Exxon in the 1970s. The process uses the kinetics associated with the gas phase homogeneous reaction between NOx in the flue gases and ammonia. The reaction, which reduces NO to N₂ and water vapor, takes place within a small temperature window around 1750 ± 50°F. The SCR process uses proprietary Japanese catalysts to promote the reduction of NO. This process is also dependent on the temperature at which the ammonia is injected and is most effective at between 550°F and 850°F. The NOx destruction effectiveness of these processes varies widely depending on the process, fuel used, temperature regime, and ammonia-to-NOx ratio.

2.2.2 NOx Destruction Methods and Adverse Impacts

The Thermal DeNOx method of NOx destruction is implemented by installing injectors in the convective heating section of the furnace immediately downstream of the furnace. Ammonia, mixed with air or steam as a carrier, is blown into the flue gases through these injectors. Different sets of injectors might be needed at several locations to cover all boiler operating conditions. For SCR, a large vessel containing catalyst in plate, honeycomb, or other form is installed in the flue gas path between the boiler's economizer and air preheater. Flue gas and injected ammonia are passed over the catalyst to accelerate the destruction chemistry.

Problems occurring with these two destruction methods may include the following:

- o Plugging of injector holes or coating of SCR catalyst with fly ash
- o Increased deposition of sulfuric acid in the air preheater or backend cleanup equipment because of the effect of the SCR catalyst
- o Deposition of sticky ammonium sulfate compounds in the air heaters and backend cleanup equipment
- o Ineffectiveness of SCR catalyst due to poisoning by foreign materials

These concerns will be discussed in more detail in Section 4.1 and Appendix C for selective catalytic reduction (SCR), and in Section 4.2 for Thermal DeNOx.

SECTION 3.0

IPP DESIGN FOR NOx CONTROL

This section sets out the relevant federal rules for establishing NOx emission limits, explains what limits have been imposed on IPP Units 1 and 2, and describes the boilers that IPP has purchased to meet the very stringent NOx limits. In addition, a discussion is presented on the implications of the fact that the IPP units will be base loaded units, and what impact that will have on NOx emissions.

3.1 REGULATORY CONSIDERATION FOR NOx CONTROL

BACT emission limits for a power plant must be at least as stringent as the levels set out in the Environmental Protection Agency's (EPA) revised new source performance standards (NSPS). On June 11, 1979, the EPA published revised NSPS for NOx emissions from new coal-fired utility boilers. The revised standards (Ref. 10) reflected EPA's judgment as to the NOx emission levels which could be achieved using demonstrated technology. The standards called for, among other things, NOx emission limitations of:

- a. 0.50 lb/MBtu from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;
- b. 0.60 lb/MBtu from the combustion of bituminous coals and certain other solid fuels.

Compliance with these limitations was to be determined using continuous monitoring of the thirty-day rolling average NOx emissions.

The distinction between the 0.50 lb/MBtu limitation for subbituminous coals and 0.60 lb/MBtu for bituminous coals was a result of EPA's concerns expressed by the Administrator in the preamble to the promulgated NSPS (Ref. 10):

"Based on discussions with the boiler manufacturers and on an evaluation of all available tube wastage information, the Administrator has established an NOx emission limit of 260 ng/J (0.60

lb/million Btu) heat input for the combustion of bituminous coal. The Administrator believes this is a safe level at which tube wastage will not be accelerated by low-NOx operation."

In support of the NSPS for coal-fired utility boilers, EPA Background Document (Ref. 11) contained specific references to a manufacturer's statements relative to the combustion of eastern coal versus low-rank western coals. EPA states that:

"EPA has concluded from field testing results, discussions with industry, and the advice of our research laboratories that an NOx emission limit of 260 ng/J would be appropriate for new units which burn eastern coals. ...Low sulfur, low rank western coals would be classified in the proposed regulations as 'sub-bituminous coal,' according to ASTM standards. There may be some western bituminous coals which have high tube wastage potentials due to high sulfur contents. The combustion of these coals would be subject to the same emission limits as eastern coals." (emphasis added)

Reference 12 discusses the characteristics of the class of coal that will be used in the two IPP units. It is clear from the procedures outlined in ASTM D388, "Classification of Coals by Rank," that the IPP coal is considered a Class II Group 4 Coal Rank, or a High Volatile B bituminous coal. The applicable NSPS NOx limitation for this coal is therefore 0.60 lb/MBtu. As pointed out in Reference 12, this coal is indistinguishable from some eastern bituminous coals and has higher sulfur content than subbituminous coals.

3.2 NOx EMISSION LIMITS FOR IPP UNITS 1 AND 2

On June 12, 1980, EPA issued IPP a Conditional Permit to Commence Construction and Operation (Ref. 13) of a 3,000 MW, four-unit project at the Lynndyl site. On December 3, 1980, the Utah DOH issued a permit to construct the IPP project (Ref. 14). Both permits established limitations on the emissions of sulfur dioxides, particulate matter, and nitrogen oxides. Compliance with these limitations was to be determined using continuous emissions monitoring of opacity, sulfur dioxide, and nitrogen oxide. Subsequent to granting of the permit, IPP selected vendors for the major equipment including the boiler and the sulfur dioxide and particulate matter flue gas treatment systems. These selections were made based on a number of considerations including the regulatory requirements that needed to be met in order to justify this

venture economically. The following paragraphs discuss some of the regulatory and operational requirements as they relate to nitrogen oxides (NOx) control on IPP Units 1 and 2.

EPA Region 8, in determining the BACT limit for NOx at IPP, imposed a limitation of 0.550 lb/MBtu, notwithstanding the NSPS standard of 0.6 lb/MBtu. EPA explained this departure from the Administrator's NSPS findings regarding the achievable NOx emission level for bituminous coals on the grounds that the sulfur content of the IPP bituminous coal was "low" and "that an existing plant, burning coal similar to that which IPP will burn, achieves a NOx limit of 0.54 lb/MBtu on a 30-day average without excessive slagging problems" (Ref. 13). EPA recognized that, in establishing this more stringent limitation, it was going beyond what had been demonstrated and EPA made clear that any limitation more stringent than 0.550 lb/MBtu would not be justified. Thus, experts at the EPA's Industrial Environmental Research Lab cautiously observed that an "emission limitation of 0.55 lb/MBtu is probably achievable..." but emphasized that a "NOx emission limit of 0.5 lb/MBtu (on a continuous basis) cannot be supported based upon available data" (Ref. 15).

Utah DOH, in the permit it issued, did not depart from the NSPS standard for bituminous coal. Thus, the limit on NOx in the Utah permit is 0.6 lb/MBtu.

3.3 OPERATIONAL CONSIDERATIONS FOR NOx CONTROL

3.3.1 Boiler Description

In order to meet the 0.550 lb/MBtu NOx requirement in the EPA permit, IPP selected one of the most advanced second generation NSPS boilers available to the utility industry. The boilers selected for IPP Units 1 and 2 were Babcock & Wilcox (B&W) natural circulation, balanced draft, single reheat boilers shown in Figure 3-1. These boilers will incorporate a burner system designed by B&W to operate at low levels of NOx without creating adverse side effects. The system incorporates a compartmented windbox for precise control of the combustion air (Figure 3-2a) and a low-NOx burner design developed by B&W (Figure 3-2b). The B&W dual register burner provides the control of stoichiometry and the mixing of fuel and air necessary to achieve extremely low levels of NOx emissions (see Section 2.1.2). The windbox and burner

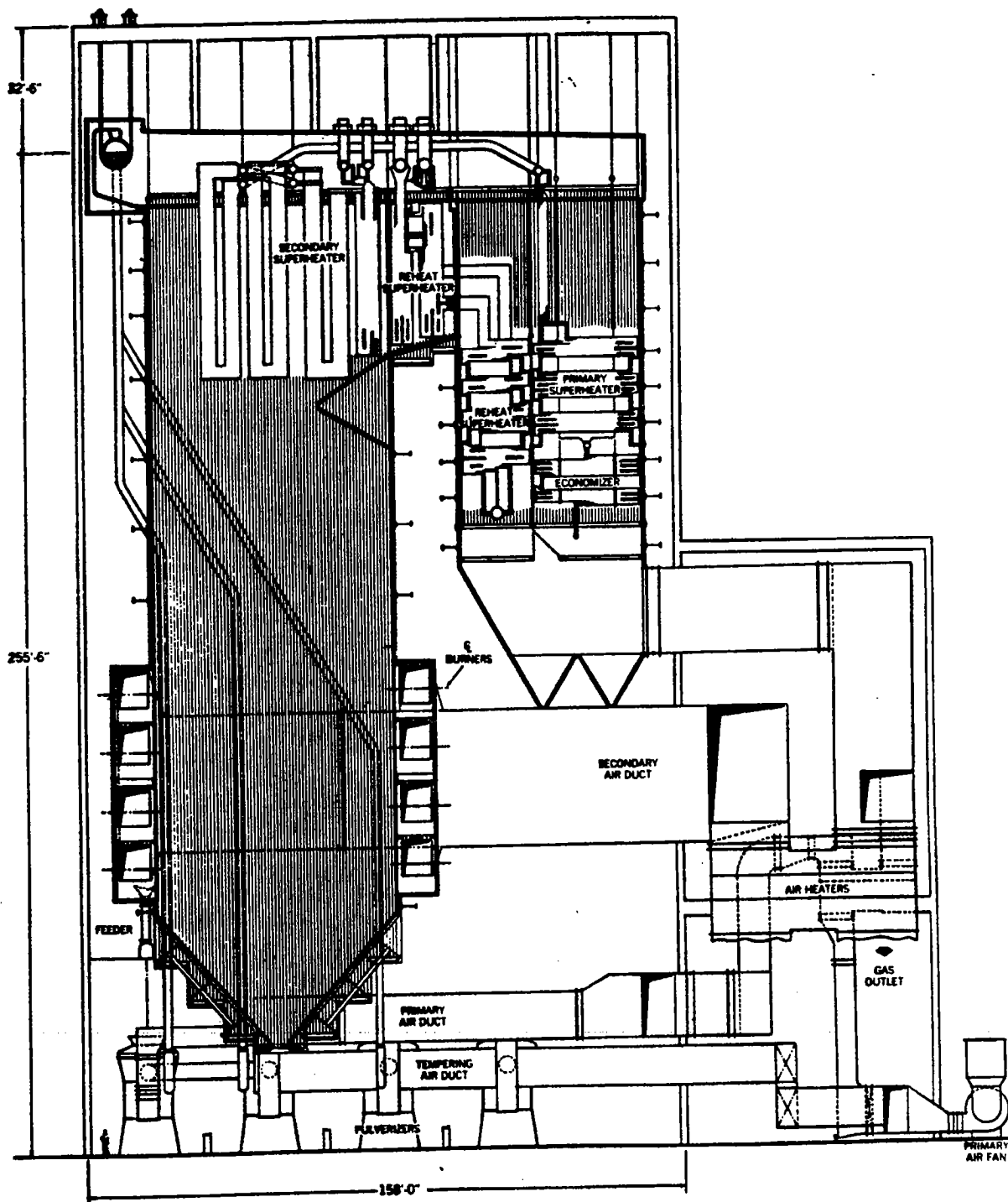
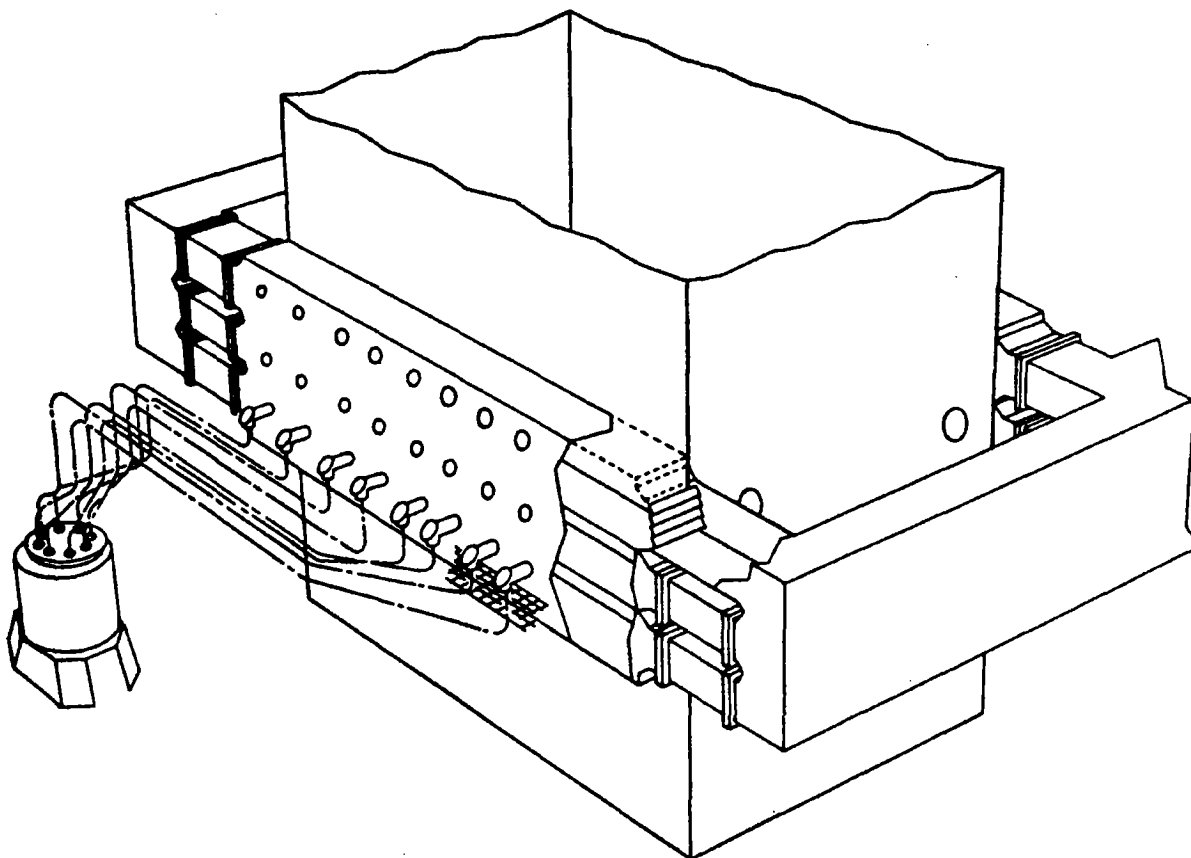
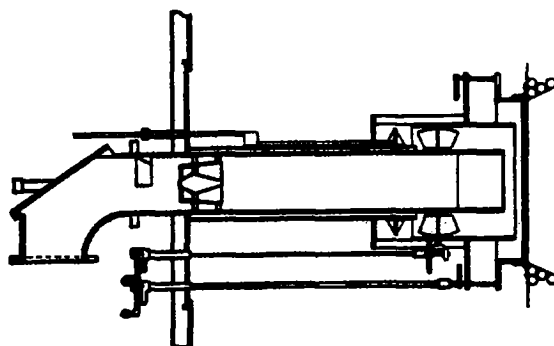


Figure 3-1. IPP boiler configuration for Units 1 and 2.

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a. Compartmented windbox.



b. Low-NOx dual register burner.

Figure 3-2. Babcock and Wilcox low-NOx burner system.

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combination is one of the most advanced systems in the industry and has been used on a large number of new second-generation boilers designed to comply with the revised NSPS for both subbituminous and bituminous coals. This system has the most demonstrated experience of the new low-NOx designs and has achieved some of the lowest emission levels.

IPP has gone to great lengths to ensure that the availability and reliability of these units are maximized to the extent possible. Reference 16 entitled, "The Specification and Design of High Availability Boilers for the Intermountain Power Project" describes in detail the considerations that went into the selection of the boiler and auxiliaries. The boiler was designed to fire Utah bituminous coals having a wide variety of properties shown in Appendix D. These coals have slagging and fouling tendencies which range from high to medium slagging and from low to medium fouling (see Appendix B). The integrated burner and boiler design was selected to take these conditions into consideration. The large amount of experience with the B&W integrated boiler and burner design will not only ensure high reliability and availability, it also ensures the highest probability of compliance with the NOx emission regulation of 0.550 lb/MBtu imposed by the EPA PSD review. This system represents the state-of-the-art technology for NOx control for coal-fired boilers.

3.4 OPERATING IMPACT ON NOX EMISSIONS

The economic evaluation of the IPP plant was based on assumptions concerning the load demands of the units. This evaluation indicated that in order for the project to remain feasible, these demand criteria must remain close to the predicted values. The units were designed to operate as base loaded units, rather than cycling units, with an operating capacity factor in excess of 80 percent over the majority of their useful life. The projected time at loads between 75 and 100 percent of rated load averages approximately 78 percent of the time. The units will spend approximately 58 percent of their time at full load. Some of this full-load operation could be for prolonged periods of time without load drops for anything other than maintenance and routine problem solving.

The loading condition of a particular unit will affect the NOx emission levels of a boiler on a 30-day rolling average basis. Two general

types of loading scenarios exist for most utility boilers--cycling and base loaded. Cycling units, or units which change loads drastically on a day-to-day, hour-by-hour basis, may have significantly different 30-day averages than do base loaded units such as the IPP units. For instance, a cycling unit which exhibits a NOx versus load characteristic of decreasing NOx with decreasing load might show 30-day NOx averages that were well below its full load instantaneous NOx emission level. This would be particularly true if much of the cycling unit's load were below the maximum rated load. On a base loaded unit, on the other hand, the 30-day averages would approximate the instantaneous NOx emission levels if the unit were to be loaded at one load for a period approaching 30 days. It should be pointed out that units can exhibit varying NOx versus load characteristics, ranging from decreasing NOx with decreasing load to cases where the NOx emissions are increased with decreasing load (see Sec. 4-5, Fig. 4-6).

The exact NOx versus load characteristics of the IPP boilers cannot be predicted with any certainty. In addition, the exact minimum instantaneous NOx emissions cannot be accurately predicted. However, a review of some of the existing B&W boiler applications for bituminous coal show that the delivered NOx emissions varied from 40 percent to 97 percent of the regulated emission requirements. This wide range in delivered NOx emissions is due to a multitude of variables, including variabilities in coal properties, and the fact that, due to practical limitations, no two boilers are ever constructed identically. In any event, B&W has provided a guarantee to meet the 0.55 lb/MBtu NOx limit over the load range of the IPP boilers. B&W has provided adequate margin in the design of the IPP boiler for the uncertainty in delivered NOx emissions based on the coal variability as well as anticipated operational variables and the design considerations. For high availability and reliability, any further reduction in NOx emissions beyond 0.550 lb/MBtu could severely jeopardize the ability to comply as well as negate the efforts directed toward cost-effective reliable boiler operation.

3.5 SUMMARY

EPA performed a PSD review for the four IPP steam generating units located near Lynndyl, Utah. Their determination was that BACT for these units was an emission limitation of 0.550 lb/MBtu for NOx. On June 12, 1980, EPA

issued a Conditional Permit for these units. Subsequently, the State of Utah DOH issued its Permit to Construct for these units.

Based on the stringent emission limitation of 0.550 lb/MBtu, IPP selected an advanced second-generation NSPS design boiler offered by B&W. The boiler was integrated with a low-NOx burner system such that the integrated system could achieve the stringent NOx levels required by the permits.

The IPP units are designed to be base loaded at near full load. B&W designed the units to operate in this mode, taking into account such variables as mills-out-of-service, slagging, coal quality, and variable coal heat content, as well as other normal day-to-day operational difficulties. Sufficient margin in NOx was provided to account for the occurrences--any decrease in the required margin might jeopardize the ability of the boilers to operate reliably. Based on this required operating mode and consequent design requirements, this boiler is considered state-of-the-art and therefore should be considered BACT.

SECTION 4.0

OTHER NOx CONTROL METHODS

This section discusses the five NOx reduction techniques requested by the Utah DOH (Ref. 2) for review:

- Selective catalytic reduction (SCR)
- Thermal DeNOx®
- Overfire air ports
- Lower excess combustion air
- Decreased plan heat release through boiler derating

Each of the five techniques has an NOx reduction or destruction effectiveness associated with it depending on the fuel and how much NOx control is presently incorporated into the boiler. In some cases with post-combustion NOx treatment, the effectiveness may be limited by certain increases in emissions of ammonia, sulfur trioxide, and ammonium sulfate and bisulfate. In other cases with combustion NOx control techniques, the effectiveness may be limited by carbon carryover, slagging, fouling, and/or corrosion. Each of these limitations can affect the availability and reliability of the total boiler/cleanup system if the techniques are pushed beyond their practical limits. These limiting factors will be discussed along with the effectiveness of each of the techniques.

Each technique is treated in a separate subsection. The process or mechanism description is presented along with operational considerations. The operating experiences are also discussed for these techniques.

4.1 SELECTIVE CATALYTIC REDUCTION

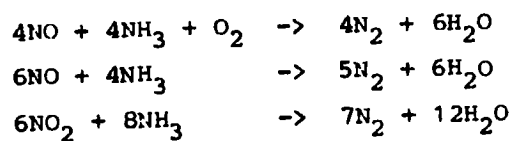
The SCR technique, developed in Japan, uses ammonia to destroy NOx with the aid of a solid catalyst. This technique has been successfully applied on a number of oil- and gas-fired utility boilers in Japan. In Southern California a demonstration has been run on an oil- and gas-fired boiler. To date, however, there is no experience in using SCR full scale on a utility boiler firing U.S. coal. Some special properties of Utah bituminous

coal which will be discussed below raise doubts as to whether this costly process would be effective on the IPP units.

4.1.1 Process Description and Operating Considerations

Between about 550°F and 850°F, in the presence of certain promoting substances (or catalysts), NO_x in flue gases can be reacted with ammonia (NH₃) to produce nitrogen (N₂) and water vapor. In order for the reactions to proceed, the ammonia must be mixed with the NO_x-bearing flue gas, which is then brought into intimate contact with the surface of the catalyst.

The chemical reactions involved are believed to be:



The application of SCR involves the injection of ammonia into the flue gas stream downstream of the economizer. The ammonia and NO_x mix and then react downstream within a large fixed catalyst element located between the economizer and the air heater. The flow path through the catalyst is arranged such that the flow is downward rather than horizontal. Downward flow through the catalyst reduces the potential for settling of dust on the catalyst surfaces by particle migration. Figure 4-1 diagrammatically presents the overall SCR process chemistry and the potential fates of major nitrogen and sulfur species in the flue gas. The figure illustrates that ammonia, sulfur trioxide, and ammonium sulfate and bisulfate are collected in the coal ash and deposit in the air preheater or are passed on into the SO₂ scrubber and baghouse as gaseous or liquid substances.

A recent report prepared by Stearns-Roger Engineering Corporation for LADWP included a discussion of the uncertainties involved in potential application of the SCR process to large boilers burning U.S. coals. Though many of the important points made will be brought out in this section, for completeness, relevant passages of the Stearns-Roger report are quoted verbatim in Appendix C.

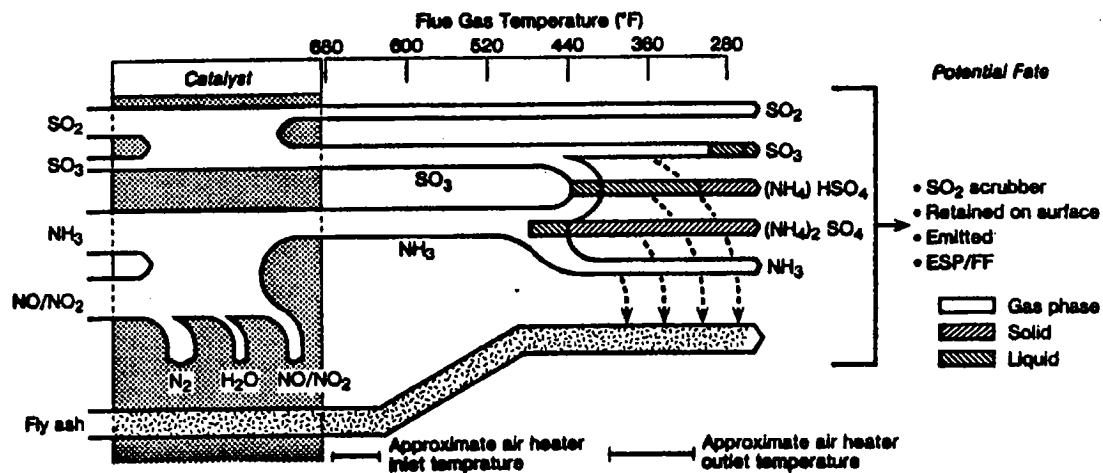


Figure 4-1. Fate of major nitrogen and sulfur species in the SCR process (Ref. 19).

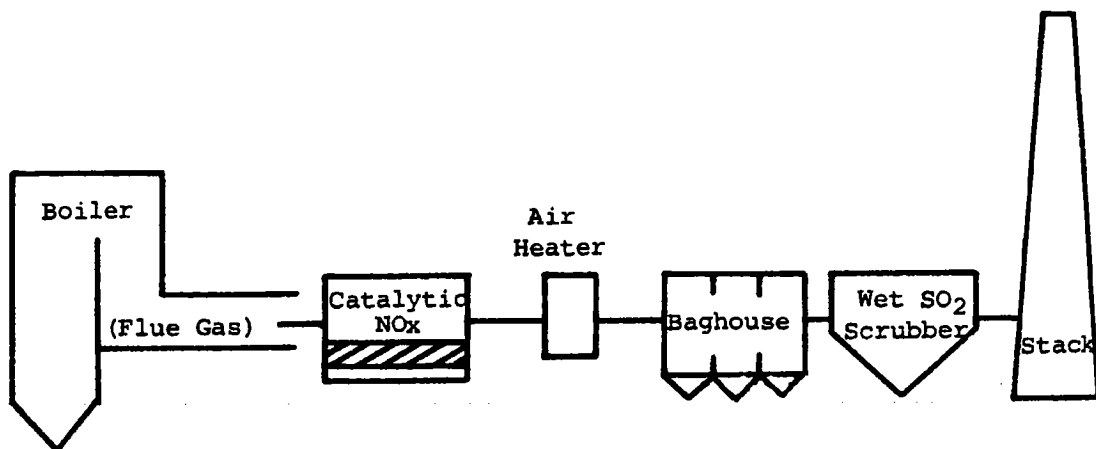


Figure 4-2. Catalytic NO_x destruction in a system using a fabric-filter baghouse for particulate control.

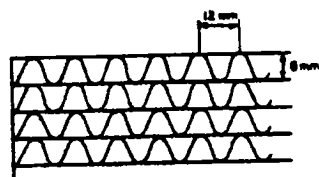
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The temperature requirement of the NOx-reducing chemistry of SCR dictate the placement of the catalyst vessel in the region of the boiler between the economizer and air heater, as shown in Figure 4-2. This figure shows a fabric filter (FF) or baghouse downstream of the air preheater. Baghouses have become accepted as far more reliable than hot-side electrostatic precipitators for particulate emissions control on boilers fired with low-sulfur coal. In particular, for IPP where the stringent particulate emission limitation of 0.020 lb/MBtu dictates the use of highly efficient and reliable collection equipment, it was determined that a baghouse would be superior to a hot-side precipitator. However, a baghouse cannot be placed upstream of the air heater as state-of-the-art filter fabrics used in baghouses cannot withstand this high-temperature environment. The SCR process, however, requires a high-temperature environment (550 to 850°F).

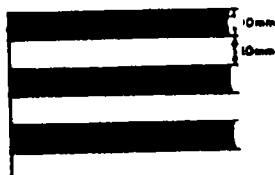
Consequently, the SCR process must be placed in the unfiltered flue gas upstream of the air heater and any influence on flue gas properties would be potentially passed on to the air heater and on downstream to the particulate and SO₂ control devices. In this configuration, the catalyst receives full fly ash loading--which is a major factor affecting catalyst design. For example, fly ash scouring effects must be used in keeping active catalyst surfaces exposed, whereas prevention of pluggage or bridging of catalyst passages by fly ash particles is mandatory. Placement of the SCR in the high dust loading configuration, upstream of the baghouse, can result in shortening of its lifetime as well as in maintenance problems.

For coal applications of SCR, parallel passage catalyst assemblies illustrated in Figure 4-3 are necessary. Variations in catalyst composition and configuration are the factors which perhaps most distinguish the various vendors of catalytic systems. Actual compositions are usually proprietary but can be characterized by active catalyst ingredients deposited in an inert metallic or ceramic base carrier. For example, one system primarily consists of vanadium pentoxide (V₂O₅) distributed in a titanium dioxide (TiO₂) base.

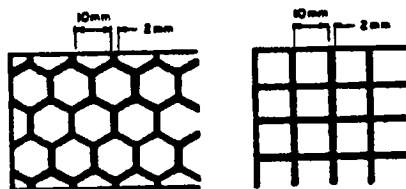
Numerous unresolved engineering and operational uncertainties raise serious questions concerning the present applicability of SCR to coal-fired power plants, irrespective of process integration issues. The concerns raised by long-term application of SCR on large coal-fired generating units are summarized in Table 4-1. The major points will be discussed below. The key



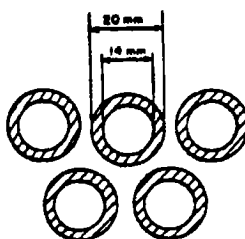
a. Metal Honeycomb



b. Parallel Plate



c. Ceramic Honeycomb



d. Tubular

Figure 4-3. Parallel passage SCR catalyst designs (Ref. 17).

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TABLE 4-1. CATALYTIC NOx OPERATIONAL AND TECHNICAL
ISSUES (REF. 17)

Process Consideration	Issues and Uncertainties
1. NOx Removal	
a. Catalyst Life	<ul style="list-style-type: none"> o Catalyst integrity (erosion, cracking, plugging) o Catalyst replacement frequency and costs
b. Catalyst Activity	<ul style="list-style-type: none"> o Long-term de-nitrification efficiency o Catalyst quantity o Efficiency and response time under transient operations o Design and costs of sootblowing/waterwashing facilities o Wash disposal
c. Influence of Coal Properties	<ul style="list-style-type: none"> o Fly ash effects on catalyst life and activity o Site specific
d. Startup/Shutdown	<ul style="list-style-type: none"> o Adverse effects of boiler startup fuels on catalyst o Catalyst bypass
e. Boiler Design/Operation	<ul style="list-style-type: none"> o Effects of variable inlet NOx on ammonia carryover, NOx removal efficiency, and size of catalyst
2. Process Control	
a. Ammonia Control	<ul style="list-style-type: none"> o Control system and instrumentation development o Load-following ability o Achievable NOx removal efficiency
b. Flue Gas Distribution and Temperatures	<ul style="list-style-type: none"> o Ammonia/NOx distribution and contacting in large ducts o Flue gas temperature distribution and monitoring
3. Installation	
a. Retrofit	<ul style="list-style-type: none"> o Space availability and structural requirements o Ducting and fans o Compatibility with flue gas temperatures o Capital costs o Plan area
b. New Units	<ul style="list-style-type: none"> o Capital costs
4. Heat Rate Impact	
a. Flue Gas Temperature	<ul style="list-style-type: none"> o Restriction in flue gas exit temperature due to catalyst operating requirements
b. Draft Loss	<ul style="list-style-type: none"> o Auxiliary power
5. Resources	
a. Catalyst	<ul style="list-style-type: none"> o Availability and cost o Recycle/disposal
b. Ammonia	<ul style="list-style-type: none"> o Availability and cost o Storage/handling o Industrial hygiene and safety
6. Flue Gas Byproducts	
a. Ammonia Utilization	<ul style="list-style-type: none"> o Carryover of unreacted NH₃ to air heater inlet
b. SO ₂ to SO ₃ Conversion	<ul style="list-style-type: none"> o Oxidation of SO₂ to SO₃ across catalyst
c. NH ₃ /SO ₃ Byproducts	<ul style="list-style-type: none"> o Formation and deposition during passage through downstream ducts and equipment

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unresolved issues are the potentially major impact of operating and maintenance problems caused by the use of an SCR system; catalyst lifetime limitations; and the process control requirements. These unresolved issues could potentially impact the reliability and availability of a commercial application such as IPP.

Catalyst lifetime, guaranteed for one or two years by process vendors, is unsubstantiated for coal-fired applications and awaits verification through large-scale demonstration tests on U.S. coals. This is an especially critical issue since catalyst replacement can represent about half of the total system cost. The present method of control of the ammonia injection rates in SCR involves the use of inlet and/or outlet NOx measurements to achieve the correct NOx destruction. Use of this method can result in ammonia breakthrough or excessive ammonia emissions. The most direct method of control would incorporate an ammonia breakthrough feedback control system to prevent ammonia emissions. To date no adequate ammonia injection control system has been demonstrated which can reliably tailor the proper ammonia injection rate to achieve high NOx removal efficiency over the normal ranges of boiler operation without causing excessive ammonia emissions. This excessive ammonia carryover can create problems with the air preheater, baghouse, and ductwork as a result of the formation of corrosive and sticky substances when the ammonia reacts with sulfur compounds. Taken as a whole, these issues translate into substantial operational and economic uncertainties for the SCR process, even without considering plant process integration.

Having both SOx and very high particulate concentrations present in an SCR unit can cause problems with the SCR system and the systems downstream. These problems are mainly due to: (a) conversion of sulfur dioxide (SO₂) to sulfur trioxide (SO₃) which reacts with the ammonia introduced by the SCR unit to form sticky ammonium sulfates, or combines with water in the air preheater to form highly corrosive sulfuric acid; and (b) catalyst blinding or poisoning due to the presence of coal ash, with its content of many different potentially contaminating minerals, in the catalytic unit. These two subjects will be discussed below.

Catalyst Blinding or Poisoning

A catalyst by definition is a chemical "matchmaker" which, although it is not consumed in a chemical reaction, helps other materials to react with

each other. The physical and chemical purity of the catalyst and the intimacy of its contact with the flue gases can be critical to determining whether the catalyst will continue to do its job.

If the catalyst surface becomes covered with a fly ash coating which is not easily permeable by the flue gas, the catalyst will become ineffective. A more subtle but equally important effect in catalytic reactors is "poisoning" of the catalyst material itself by trace contaminants which destroy the effectiveness of the catalyst.

Coals contain most of the known chemical elements combined into a vast number of mineral forms. There is relatively narrow experience in burning Utah bituminous coal in large boilers, and no full-scale experience in SCR with this type of coal. Experience on boilers is limited to a few utilities in the general vicinity of the mines. Because the properties of various coals vary so greatly, it is difficult to predict whether SCR catalyst poisoning will occur when burning Utah bituminous coal. What does seem to be accepted knowledge at present, though, is that SCR catalysts lose their effectiveness with time, and that the cost of replacing spent catalyst over the lifetime of a plant far exceeds the original cost of the SCR equipment. If elements in the Utah bituminous coal caused poisoning of the catalyst, the normal life of the catalyst would be decreased. These elements might include sodium, potassium, and calcium as discussed in Section 4.1.2. Depending on the amount of decrease, the replacement cost over the lifetime of the boiler could be substantially increased and the boiler availability would also be decreased. The technology of these catalysts is proprietary to foreign countries, which raises the question of catalyst availability in the years to come. If the lifetime is shortened and catalyst availability is limited, this could jeopardize IPP's ability to reliably comply with more stringent NOx limitations.

Formation of SO₂ and Ammonium Sulfates

Unfortunately, contact of SO₂ and O₂ in the flue gases with the catalysts which promote NOx destruction also causes a higher percentage of the SO₂ to be oxidized to SO₃, which is a much more strongly reactive chemical than SO₂. Some of the SO₃ then combines with some of the ammonia which is needed in the SCR process and form ammonium sulfate and ammonium bisulfate. For many years it has been known (Refs. 18, 19) that one or both of these compounds in

a boiler's air preheater can form sticky deposits on the air heater surfaces. These deposits block off the flow and reduce heat transfer efficiency and are not readily removed while the boiler is in operation. In some cases the deposits can build to unacceptable levels in a matter of only a few hours which could necessitate a boiler shutdown (Ref. 20). Another problem caused by SO_3 is formation of sulfuric acid (H_2SO_4) when water vapor (H_2O) combines with SO_3 in the air preheater. Because the air heater extracts heat from the flue gases in order to heat the combustion air, the sulfuric acid can condense on air heater surfaces as the flue gases become cooler. This sets design limits on the use of the energy in the flue gas, and thus causes an increase in fuel consumption throughout the life of the generating unit. Both the potential for air preheater blockage by ammonium sulfate and bisulfate and the corrosion potential due to increased SO_3 can result in increased operating costs and the loss of availability.

Another potential problem is blinding of the baghouse filter fabric due to the sticky nature of the ammonium sulfate or bisulfate. If sticky particles were selectively retained during the bag cleaning process, they could eventually build up to the point where flow through the bag fabric was seriously impeded. This would increase the pressure drop across the fabric, leading to more penetration of the fabric by submicron particles and thus to increased stack plume opacity. The amount of ammonium sulfate and bisulfate formed is dependent on the SO_3 in the flue gas stream and the amount of ammonia breakthrough from the SCR. The SO_3 depends on the SO_2 -to- SO_3 conversion rate in the SCR as well as SO_3 formed by catalysis in the boiler itself through contact with superheater tube deposits. According to Reference 23, the ammonium sulfate and bisulfate can form either "on the cake or in the bag cloth to form deposits which may irreversibly increase the pressure loss and reduce bag life." The cost of particulate removal would then be increased depending on the amount of decreased lifetime.

Ammonia and its sulfate may also cause sticking of ash in the hoppers into which the collected ash falls at the bottom of the baghouse; this would cause problems in emptying hoppers.

The potential for increased SO_3 emissions from the operation of the SCR could result in reduced bag life particularly if the SO_3 concentrations were high enough to cause condensation on the bag. In addition, if the SO_3

did not condense on either the air preheater or the bags, according to Reference 21, this added SO₃ emission would decrease the scrubber efficiency. As with the ammonium sulfate and bisulfate, the cost of particulate removal would be increased. If scrubber efficiency were decreased, this could result in increased scrubber costs through design changes or failure to meet the scrubber efficiency requirements specified in the permit.

4.1.2 Operating Experience with SCR

In order to have confidence in application of a pollution control technique to boilers in a large utility plant, large-scale application under similar conditions is necessary. To date, there have been no large-scale demonstrations of SCR on U.S. coals.

The EPA recently published the results of a test of the Hitachi-Zosen SCR process run at 1/2 megawatt scale on a small slipstream from a utility boiler burning eastern coal in Georgia. A paper co-authored by J. D. Mobley of EPA's Industrial Environmental Research Laboratory (Ref. 22) concluded that "fly ash properties at the United States test site did affect operation of the Hitachi Zosen process." Catalyst configuration had to be changed. Measurable deterioration in catalyst activity occurred in six months; regeneration was required to restore the activity. It was not determined how long the effects of regeneration would last, and a one-year catalyst life was not confirmed. Ammonia carryover levels were approximately 55 ppm at design conditions. Measured concentrations of SO₃ in the flue gas increased by 12 ppm in the SCR unit. Problems were experienced with SCR unit monitors and controls. No definite conclusion was reached with regard to catalyst life at high NO_x removal values. The EPA test of the Hitachi-Zosen SCR process established the potential effectiveness on some U.S. coals on a laboratory scale. The full developmental process of SCR should follow a procedure similar to that of the SO₂ scrubber technology development. The development of sulfur oxide scrubber technology proceeded with an orderly experimental program starting with subscale studies and proceeding to full-scale verification of the subscale findings. The U.S. sulfur oxide scrubber development consisted of: (1) a demonstration at small (1 to 5 MW) scale for a year or more with flue gases representative of those to be controlled eventually at full scale, and (2) a

demonstration at about 100 MW scale for at least one year under similar conditions to verify that problems of scaling could be solved for this type of flue gas. A similar orderly program for SCR NOx removal technology development in the U.S. would be appropriate.

The Electric Power Research Institute (EPRI) has also run a small-scale demonstration (2.5 MW) of the Kawasaki SCR process, using a small slipstream from a utility boiler burning subbituminous coal. This represents the first step in an orderly development program for SCR NOx removal technology in the U.S. Although the results were encouraging, again they were at very small scale: roughly 1/600 the scale of the Intermountain Power Plant. There were problems with ammonia measurement and control due to contamination of the ammonia, and due to corrosion and plugging of the instrumentation system with ammonium sulfates. Concentrations of 13 ppm SO₃ (dry basis, corrected to 3 percent O₂) at the exit of the SCR unit caused the formation of ammonium and aluminum sulfates deposits in the air preheater which doubled its pressure drop (from 6 to 12 in.H₂O) in only 3-1/2 days. Some portions of the air heater cold side basket leading edges were totally choked with deposit accumulation.

Although an SCR catalyst can be chosen for lower conversion of SO₂ to SO₃, it is not as simple to control formation of SO₃ upstream in the furnace, and the potential occurrence of this type of problem on a full-scale application cannot be dismissed.

Both the EPA and EPRI subscale SCR programs utilized slipstreams from larger boilers. On full-scale applications where slipstreams are used instead of NOx removal on the full flue gas stream, many of the potential problems not only with downstream equipment (air preheaters, scrubbers, and particulate collection devices), but with the SCR system, are masked. The dilution of the slipstream if returned to the main stream masks the effects of ammonia breakthrough, SO₃ emissions, and ammonium sulfate and bisulfate on equipment located downstream of the SCR. In the case of IPP, this would be the air preheater, baghouse, and the SO₂ scrubber as well as the ducting leading to this equipment. In this slipstream condition, the effects of full stream flow through the SCR are potentially masked by the size consideration. Unpredictable problems in size scale up could potentially affect the SCR removal efficiency. The next orderly step in a NOx removal technology

development program in the U.S. would be to test an SCR system with a full flue gas stream on a full-scale utility boiler with the appropriate back-end cleanup systems. This next step should be designed to use equipment and fuels common to the U.S. utility market.

An important point to note with regard to SO_3 conversion from SCR units is the fact that a catalyst might be chosen for lower SO_3 conversion, however, control of the SO_3 formed through combustion and catalysis in the furnace is no simple matter. Therefore regardless of the amount of SO_3 conversion present from the SCR, there will always be a measurable amount of SO_3 from the furnace flowing through the SCR and into the downstream equipment. This SO_3 coupled with the ammonia breakthrough from the SCR presents the possibility of formation of substances that can shorten the baghouse life, decrease the scrubber efficiency, and create potential problems with ducts and the air preheater.

Larger scale experimental demonstrations have been run in Japan. The only unit of over 100 MW capacity on which published results are available appears to be Takahara Unit 1, which used Australian and South African coals. This demonstration was studied by Stearns-Roger for LADWP, and some excerpts from their report (Ref. 23) are given in Appendix C. It is likely that the coals used at Takahara had quite different ash properties from those of IPP coal.

Data on the specific coals burned at Takahara do not appear to be available. However, some published data on a limited number of South African and Australian coals were extracted from Reference 24 and are presented in Appendix D. These data show that the Australian and South African coals contain lower sodium-potassium contents (0.6-1.5 percent as oxides) than the Utah bituminous coals (1.5-3.7 percent as oxides) being considered for IPP. Kawasaki Heavy Industries (KHI) has implied that more than 1.6 percent total sodium-potassium contents significantly decreases the activity of their catalyst (Ref. 25). Calcium is also stated to be of concern in poisoning of SCR catalyst (Ref. 23). Table D-1 in Appendix D shows that the average calcium oxide (lime) content for the seven IPP candidate coals is 9 percent, while the average for the two South African coals is 4 percent and for the five Australian coals is less than 3 percent.

These comparisons of the Utah coals to the foreign coals do not prove that catalyst blinding would occur in an SCR unit processing Utah coal flue gases much more quickly than blinding would occur at Takahara. However, it does point out that there is a concern regarding the possible application of SCR to IPP. It appears significant, however, that total sodium-potassium contents of the Utah coals are at or above the 1.6 percent which was implied by KHI to be the maximum which could be handled without catalyst blinding problems. If rapid blinding were to occur at IPP, the catalyst life might become prohibitively short. The cost of replacement and the availability of the unit would then be adversely affected.

The most significant fact about the Takahara demonstration was that a hot-side electrostatic precipitator was used upstream of the SCR reactor. This means that the gas treated in the reactor was very low in particulate compared to the flue gas downstream of the economizers of IPP's boilers; the questions of catalyst blinding and poisoning were therefore not evaluated with relevance to possible application at IPP. A fabric filter is incorporated into IPP's design for more dependable particulate control, but is necessarily placed downstream of the air preheater, where the flue gas is too cool for SCR.

Even though the 100 MW Takahara demonstration was preceded by extensive pilot work, the initial scale-up to 100 MW could not be termed totally successful. Catalyst quantities had to be increased during the demonstration to reduce ammonia slip and its adverse effects on the downstream booster fan and air preheater. Although the SCR unit was preceded by a hot-side electrostatic precipitator, dust buildup and blockage of catalyst occurred despite the low fly ash content of the flue gas (Ref. 23).

The Takahara boiler was essentially "donated" for the purpose of discovering and solving SCR problems. The utility was able to commit its resources to find and resolve any of the problems that might result from the demonstration. Initial reliability was therefore not a major concern since this was a demonstration. Operation in the demonstration mode at IPP could not be tolerated and would not reasonably be expected of a commercial venture such as IPP. The IPP system consists of only two units which must be high availability, high reliability units. A large number of utility participants will be depending on this reliable electric power generation and could not

tolerate outages that might result from the uncertain performance of a retrofitted SCR.

The uncertainties involved in SCR are particularly significant when the high costs associated with incorporating the process into IPP at this point are considered. Black and Veatch have estimated that the total cost impact to the project would be \$1,694,000,000. The added cost of the SCR conceivably could render the Intermountain Power Project economically unfeasible.

4.1.3 Summary of Status of SCR

The present status of SCR is that: (a) no demonstrations have been run at more than 1/600 of IPP's scale on boilers burning U.S. coals; and (b) no information appears to be available on boilers anywhere in the world in which SCR was applied at over 100 MW scale for an adequate length of time in a system using fabric filter (baghouse) particulate control. SCR is therefore not sufficiently developed technically for application to IPP.

Major uncertainties exist in the following areas:

1. The length of a catalyst's effective lifetime in a high solids loading flue gas stream containing relatively high amounts of potential catalyst poisons.
2. The impact on operations and maintenance of a large system in which an air heater, a fabric filter baghouse, and a wet SO_x scrubber operate downstream of an SCR unit.
3. The lack of a reliable method of monitoring ammonia concentrations in the flue gas.

4.2 THERMAL DeNOx

The Exxon Thermal DeNOx process, which takes place at fairly high temperatures and requires no catalyst, has been demonstrated on a number of gas- and oil-fired boilers in Japan, and on one in the U.S. For coal, however, there apparently have been no applications to date; the process has been investigated only in short-term laboratory tests.

4.2.1 Process Description and Operating Considerations

The Thermal DeNOx technology developed and patented by Exxon Research and Engineering (U.S. Patent No. 3,900,554) uses ammonia (NH₃) to react with

oxides of nitrogen in the flue gas to form nitrogen and water. The desired reaction occurs without a catalyst in the temperature range of 1600°F to 1800°F with an optimum temperature at about 1750°F. For utility application, the goal would be to locate the ammonia injection grid at the optimum temperature location.

The process chemistry relies on the selective reaction between NH_3 and NO_x to produce nitrogen and water. This reaction proceeds in the presence of excess oxygen within a critical temperature range. The overall NO_x reduction and production reactions are summarized in Equations (4-1) and (4-2):



In typical flue gas environments, the NO reduction shown as Eq. (4-1) dominates at temperatures around 1740°F. At higher temperatures, the NO production reaction shown as Eq. (4-2) becomes significant, and above 2000°F, the injection of NH_3 is counterproductive, causing increased NO_x . As temperatures are reduced below 1600°F, the rates of both reactions become extremely low, the NO reduction falls off drastically, and part or all of the ammonia flows through unreacted.

In a utility boiler, the correct temperature region for Thermal De NO_x would generally occur just downstream of the furnace, in the convective steam-heating section. An example is shown in Figure 4-4, taken from a paper published by LADWP on a test of Thermal De NO_x on an oil- and gas-fired boiler (Ref. 26). An injection grid placed across the boiler's cross section was used to distribute the ammonia.

The nature of the convective section is that it contains banks of hundreds of tubes (tubes about 2" in diameter) through which the steam passes to be heated by the flue gas which flows past the tubes on the outside. The tubes are spaced as closely together as possible while avoiding fouling of the surfaces with fly ash or its constituents. The hot flue gas cools rapidly as it flows through this section, losing its heat to the steam. Due to the close spacing of the tubes and the rapid cooling of the gases, it is very difficult to design a system which will inject and rapidly mix ammonia at precisely the

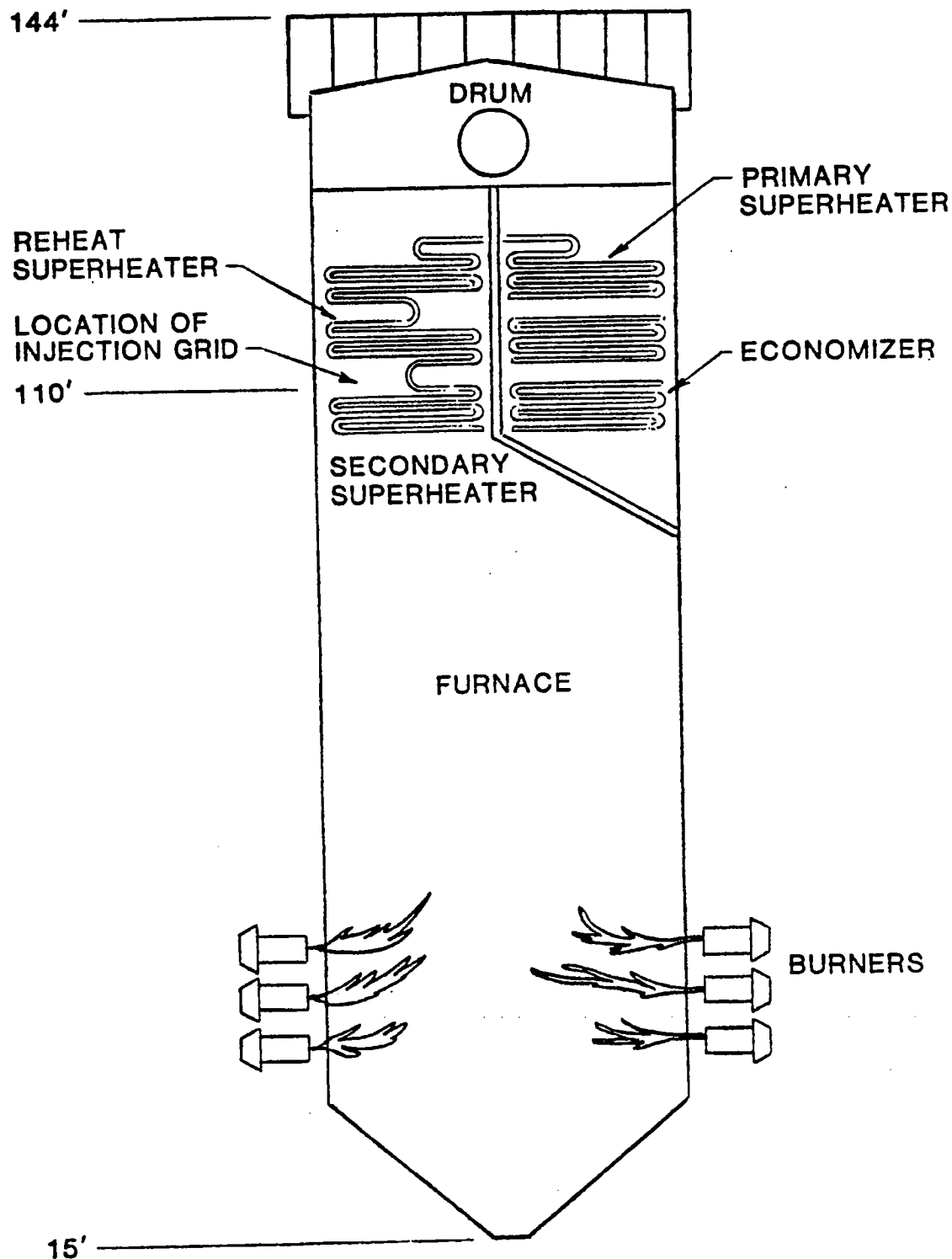


Figure 4-4. Thermal DeNOx system - location of injection grid in short-term demonstration on oil- and gas-fired boiler (Ref. 26).

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right flue gas temperature needed to achieve NOx reduction. If the ammonia is injected into too hot a region, NOx will be increased rather than reduced, as the nitrogen in the ammonia (NH₃) is oxidized. If the ammonia is injected into too cool a region, or is added in excess, some or all of it passes through the boiler unreacted and becomes another pollutant to be controlled or emitted.

In addition to temperature, the process is also sensitive to initial NOx and NH₃ concentrations. The NH₃ injection rate is generally expressed as a mole ratio relative to the initial NOx concentration. Other variables affecting performance are excess oxygen and available residence time at the reaction temperature. Minimizing excess air tends to enhance the NOx reduction, as does maximizing the residence time. Minor flue gas species such as water, sulfur oxides, and ash have negligible effects.

Nonuniformities in temperature, gas composition, and flow conditions result in lower performance. Again, concerns arise because of the escape of unreacted ammonia, which can form sticky deposits on the air heater, possibly blind the pores in fabric filters, and cause an ash odor problem. As mentioned previously in Section 4.1.1, Reference 22 states that these deposits of ammonium sulfate and bisulfate on the fabric filter bags may decrease their life. This would result in increased maintenance costs and possibly lower boiler availability.

4.2.2 Operating Experience with Thermal DeNOx

To KVB's knowledge, there has been no application of Thermal DeNOx to a coal-fired utility boiler anywhere in the world.

The most relevant work to date has been a short-term test of Thermal DeNOx on a 230-MW gas- and oil-fired utility boiler, Haynes Unit 4, by the Los Angeles Department of Water and Power; and laboratory-scale (0.3 MW equivalent) pulverized-coal-burning Thermal DeNOx tests lasting a few hours and carried out by KVB for the Electric Power Research Institute.

The results of the LADWP 230-MW short-term demonstration have been reported by H. T. Dziegiel (Ref. 26). The objective of the program was to characterize the performance of the Thermal DeNOx system. On oil fuel, the Exxon performance guarantee level of at least 46 percent NOx reduction at full load with as much as 65 ppm of ammonia breakthrough was met during the

guarantee tests. Reductions ranged from 14 percent at two-thirds of full load to about 50 percent at full load. On natural gas fuel, reductions ranged from 23 percent at two-thirds of full load to a maximum of 46 percent (more typically 40 percent) at full load. It is important to note that these reductions were on oil and gas and cannot necessarily be extrapolated to coal; this will be discussed further below. As expected, the percentage NO_x reduction was considerably reduced when the flue gas temperatures in the region of the ammonia injection system deviated from the optimum due to unavoidable operational variations.

The ammonia injection in the Haynes 4 demonstration was accomplished using a grid having a large number of small holes and located in the boiler's convective heat transfer section just downstream of the furnace (Fig. 4-4). At some unknown time during the test, one of the branches of the ammonia injection grid separated completely from its header. This is an example of the types of development problems which must be solved before a new pollution control method can be applied to utility boilers for routine long-term use in achieving emissions compliance.

In a coal-fired boiler, with its high flue-gas ash loadings, grids of the type used on Haynes 4 could suffer from high-temperature corrosion, erosion by fly ash, and pluggage of the orifices; these issues have yet to be investigated. Difficulties of this type could render Thermal DeNO_x useless for reliably achieving NO_x reductions.

Boyd (Ref. 27) of Exxon has stated that if the Haynes 4 Thermal DeNO_x design were to be done over based on Exxon's current knowledge, larger jets would be used to inject ammonia from the boiler wall rather than using the distributed grid orifices. However, he also said that "high mixing effectiveness is more difficult to achieve with wall jets especially when the unit has large cross-sectional dimensions at the point of injection." It should be pointed out that this wall injection scheme has never been used on a large utility boiler with any fossil fuel. Considering that the IPP units each have more than three times the capacity of Haynes 4--and appropriately larger cross-sectional dimensions--and that Haynes 4 burns only oil and natural gas, not coal with no applicable experience on coal or the new injection scheme, it is therefore not by any means certain that an adequate design could be achieved for IPP using the knowledge presently available. Further, it is uncertain what reliable NO_x reduction level could be achieved.

In designing their demonstration DeNOx system, LADWP had many existing boilers to choose from, and were able to make detailed temperature measurements on that boiler before deciding to proceed with detailed design. This is a luxury which is not available to IPP. LADWP found that the Haynes 4 temperature distribution in the Thermal DeNOx temperature of the boiler was rather nonuniform, no doubt partly due to the asymmetric design of the secondary superheater entrance (see Fig. 4-4), and partly due to burner adjustments which had previously been made to reduce NOx by combustion control. At IPP, temperature nonuniformities may be caused by these factors, and also by unavoidable maldistribution of coal flows between burners, differences in performance between coal pulverizers (mills) in various stages of their maintenance cycle, and time-dependent accumulation and removal of ash deposits on the furnace walls. While the spatial temperature variations on Haynes 4 were somewhat variable at a given load, on a coal-fired unit temperatures at any one point in the superheat/reheat section can be expected to vary even more from hour to hour due to the time needed to clean the furnace walls using the wall blowers, and from day to day due to coal mill maintenance and natural variations in coal properties. The result of these nonuniformities on coal would be that regions of the flue gas could experience NOx increases while others might experience high levels of ammonia breakthrough. These effects could lead to control problems in maintaining the proper NOx reduction level as well as excessive formation of ammonium sulfate and bisulfate which would affect the reliability of back-end cleanup equipment.

KVB has conducted laboratory tests of Thermal DeNOx using four U.S. coals, including Utah bituminous. These tests were performed on a 0.3 MW equivalent test boiler, several thousand times smaller than the IPP boilers. Significant reductions in NOx emissions were achieved with an ammonia-to-NOx injection volume ratio of 1:1. Due to the small scale of the experiment, good mixing effectiveness was easily achieved. However, the temperature for optimum NOx removal was found to vary over a 100°F range from coal to coal. This indicates an additional design consideration for coal, and implies possible variations from one part of a coal seam to another. The important point is that short-term tests on a small scale only demonstrate the potential effectiveness of a process--they indicate neither whether the process will be effective on a unit thousands of times larger nor the potential operational problems.

The important steps needed for application of Thermal DeNOx to coal-fired boilers in the U.S. involve the careful and orderly process of scaling. This means progressing in reasonable increments of size and running time from a few hours of operation on a laboratory boiler equivalent to 0.3 MW, to permanent implementation on a large coal-fired utility boiler--solving the many technical problems which are almost certain to be encountered along the way. The orderly process of demonstration of applicability to large coal-fired utility boilers would be similar to the methodology used for the development of SO₂ scrubber technology discussed in Section 4.1.2.

The development process for Thermal DeNOx applicability on coal-fired boilers should be designed to address the reliable effectiveness of the process as well as potential operational problems. These problems could include some of the same general types of problems associated with SCR: coating or erosion of hardware by fly ash; plugging of air heaters with ammonium sulfates; condensation of sulfuric acid on air heater surfaces; contamination of ash with ammonia; difficulties of accomplishing mixing efficiently when large quantities of nonuniform flue gases are involved; etc. Many of the problems are associated with the high ammonia breakthrough experienced with the Thermal DeNOx process.

4.2.3 Summary of Status of Thermal DeNOx

In summary, Thermal DeNOx is not developed technology from the standpoint of application to IPP: there is no experience on a scale of significant relevance to justify application to a large coal-fired utility boiler at this time.

Major concerns which still need to be resolved are selection of the proper region for injecting the ammonia; adjusting the temperatures or the injection method such that good NOx reduction results can be obtained for various conditions of load, mills out of service, and furnace wall cleanliness; and avoidance of air heater, baghouse, and scrubber problems which may be caused by ammonia and its sulfates. Injection hardware for the ammonia injection needs to be developed to the point where (a) design principles are proven for avoiding pluggage of orifices and prevention of excess abrasion of metal by fly ash, and (b) scaling principles are known well enough to be able to apply the injection method to a very large boiler with confidence that good NOx destruction performance will be achieved.

4.3 OVERFIRE AIR PORTS

As discussed in Section 2.1.2, control of the stoichiometry and mixing of fuel and air is the primary means of controlling fuel NOx from coal-fired boilers. Before the development of low-NOx burners for coal, the use of overfire air (OFA) ports was the only method of achieving modified stoichiometries and mixing in the primary combustion zone of coal-fired boilers. Early boilers designed to meet the 1971 NSPS for NOx used this technique. Development and implementation of low-NOx burners displaced this method of NOx control in the mid- to late-1970s. This was a result of the better control provided by the burners which allowed lower NOx reductions with reduced adverse side effects.

The Utah DOH has requested that IPP review the use of OFA as a NOx control technique on Units 1 and 2. The purpose of the evaluation would be to determine if effective NOx reductions could be achieved when OFA is used in conjunction with B&W's present integrated boiler/burner design. This section describes OFA and its operation, and provides information on operating experience with OFA when it is coupled with other NOx control methods.

4.3.1 Mechanism Description and Operating Considerations

Use of OFA ports is one means of incorporating staged or off-stoichiometric combustion on a utility boiler. This technique involves placing air ports, through which some of the combustion air is supplied, directly above the burner zone. By diversion of a portion of the combustion air, combustion in the active burner zone takes place in an oxygen-deficient environment. Addition of the secondary combustion air from the OFA ports completes the combustion process before the products reach the convective section of the furnace. This technique was the primary means of control that boiler manufacturers used to comply with the 1971 NSPS for utility boilers. OFA was an addition to the pre-NSPS design boilers.

One of the characteristics of the use of OFA is that it causes the entire furnace in the burner zone to operate in an oxygen-deficient or reducing atmosphere. This reducing atmosphere can lead to accelerated tube corrosion and aggravated slagging tendencies as explained in Appendix B. These concerns consequently greatly limit the effectiveness of the technique

in coal-fired boilers. The IPP coals are characterized as having high to medium slagging tendencies, and low to medium fouling tendencies (see Appendix D). Therefore, the degree of NO_x reduction by use of OFA is limited by the slagging and fouling. The slagging tendencies would indicate that operation of the furnace in reducing atmospheres would exacerbate these tendencies (see Appendix B).

The effectiveness of the technique is also limited by the ability of the secondary air from the OFA ports to mix with the oxygen-deficient combustion products. This in turn limits the degree to which the primary zone can be operated oxygen deficient or how far off-stoichiometric the furnace can be operated. If the furnace is operated extremely oxygen deficient, severe slagging can occur as well as can high levels of unburned carbon carryover into the convective pass and through the backend cleanup system. In addition, since the OFA ports do not generally allow adequate mixing, stratification of the combustion products and temperatures can occur that can disturb the superheat and reheat temperature distributions, and consequently the steaming properties of the boiler. These conditions can also adversely affect the baghouse and SO₂ scrubber. The baghouse supplier (Ref. 21) for the IPP unit indicated that a change in the particle size that might accompany increased carbon formation could blind the bags as well as create adverse pressure drop problems. These would result in decreased collection efficiencies. This consequently would cause an increase in fuel use resulting in increased NO_x, SO₂, and particulate emissions as well as increased operating costs.

Diverting combustion air from the burner zone to OFA ports can contribute to slagging problems in the lower furnace due to alteration of the ash fusion characteristics in fuel-rich, or "reducing," atmospheres as explained in Appendix B. This alteration of ash properties due to the reduction of burner zone excess air can create localized fuel-rich zones in the lower furnace. These reducing (i.e., fuel rich) conditions may promote slagging, in that the ash fusion temperatures are generally lower under reducing conditions. Depending on the overall furnace stoichiometry, the general temperature level in the burner zone may be higher with OFA due to the low amount of less excess air, which normally serves as a thermal diluent in the burner zone. While this increased temperature aggravates the slagging

potential, the main factors contributing to increased wall slagging are the presence of localized areas of reducing atmospheres and possible impingement of burning char particles on the furnace walls caused by the delayed combustion which accompanies OFA operation.

Since use of OFA results in both a scarcity of oxygen and a reduction in necessary turbulence for air-fuel mixing in the burner zone, there is considerable potential for less efficient carbon burnout. The carbon burnout zone (area above the burners) is relatively low in temperature and provides only a short duration for completion of combustion. Consequently, carbon escaping the burner zone may not be completely burned before entering the quenching zone of the convective pass. In this quenching zone, no further combustion takes place. The lack of turbulence accompanied by the short, low-temperature secondary combustion zone above the OFA ports and the boiler backpass creates a definite potential for unburned carbon losses to increase with the use of OFA.

An increased level of unburned carbon represents a reduction in unit efficiency, requiring more fuel to be burned per unit electrical output. It also represents an increase in particulate loading to the downstream collection device and may produce excessive particulate emissions due both to an increased particulate loading at the control device inlet and also a possible change in particulate characteristics, notably particle size, resistivity, and "wetting" properties. High carbon concentrations could also potentially result in a fire hazard in baghouses or precipitator cavities. Spontaneous combustion has occurred in such devices, resulting in major damage to the collecting device.

Addition of OFA ports creates a second combustion stage located higher in the furnace than is normally contemplated in the furnace design. For this reason, there is a potential that the furnace exit temperature will exceed design limits. This can, in turn, lead to slagging and fouling of convective tube passes, excessive steam temperatures, and superheater and/or reheater tube metal overheating. Fouling of superheater/reheater surfaces can obviously be aggravated by high furnace exit temperature if ash leaving the furnace is still in the molten or semi-molten state. Maintenance of steam temperatures in a higher-than-design furnace exit temperature environment in general may represent efficiency losses, since more attemperation water spray

is required to cool the steam. Excessive tube metal temperatures cannot be tolerated and, to the degree that they cannot be controlled by steam attenuation, may require unit derating in order to prevent excessive tube failures. This would impose a severe economic penalty on IPP.

4.3.2 Operating Experience with OFA

In an uncontrolled boiler, that is a boiler without NOx controls (such as pre-NSPS boilers) OFA has achieved NOx reductions of 20 percent to 40 percent. This range is dependent on the furnace design and the coal characteristics. OFA was used in the early NSPS boilers designed to meet 0.7 lb/MBtu of NOx; in many cases this was only marginally adequate for compliance. In addition, boiler manufacturers' concerns about controlling tube corrosion and slagging with the use of OFA led them to explore other means of reducing NOx in NSPS design boilers. The manufacturers therefore concentrated on developing low-NOx burners that would help to eliminate some of these concerns about adverse side effects. The resulting designs prevented the lower furnace from becoming oxygen deficient while at the same time yielding NOx levels lower than those of OFA applications.

The NOx levels achieved with new low-NOx burners coupled with advanced furnaces designed to accept these burners was from 40 percent to 60 percent below the levels experienced on pre-NSPS boilers. This is compared to the 20 percent to 40 percent reductions found with OFA applications. While slagging problems still exist on some of these second generation boiler/burner designs, the severity is not generally as great and the NOx levels are significantly lower. In addition, the operational flexibility is improved with the new low-NOx burners.

One important factor when applying combustion control techniques to reduce NOx is that the NOx reduction is not equal to the sum of the reductions from the individual techniques. Addition of OFA to a boiler designed to accept low-NOx burners, for example, might in fact result in increased NOx emissions. The reason for this is that the burners are designed to achieve the proper stoichiometry during the volatilizing of the fuel-bound nitrogen and mix the combustion air after this volatilization takes place. This is accomplished by judiciously matching the fuel and air velocities as well as tailoring their mixing intensities. The mixing then takes place at the proper time and location to prevent reducing atmosphere environments in most of the

furnace region, thus minimizing the potential for slagging and fouling. Alteration of this condition consequently decreases the effectiveness of the control technique.

Using OFA in conjunction with an integrated boiler/low-NOx burner system not only changes the burner stoichiometry but also the mixing characteristics which influence the NOx reduction potential. By its very nature, use of OFA in this condition would also tend to produce an oxygen-deficient atmosphere in the furnace and exacerbate slagging and corrosion problems--the very reasons why boiler manufacturers no longer favor OFA operation. There is very little experience with the combined use of these second-generation boiler/burner designs coupled with the use of OFA. Early experimentation of the combined effects of the use of low-NOx burners coupled with OFA discussed in Reference 28 showed that use of OFA was not effective in reducing NOx below the low-NOx burner only configuration levels. In discussions with B&W, they indicated that in one instance, they measured an apparent reduction of 18 percent on recent tests during their acceptance testing of a boiler firing subbituminous coals. The exact conditions of this test were not specified and they were admittedly short-term test results. Discussions with another utility (Ref. 29) indicated that use of OFA on their bituminous coal-fired boiler equipped with B&W low-NOx burners did not decrease NOx emissions; in fact, indications were that the NOx actually increased with the use of the OFA. This unit is apparently now operating with OFA ports closed. The present data do not suggest a consistent result when OFA is applied to units incorporating the B&W new low-NOx burners.

4.3.3 Summary of Status of OFA

Based on the design philosophy behind the integrated boiler/low-NOx burner system, it is doubtful that retrofitting OFA to the IPP units would achieve meaningful, if any, NOx reductions. What little data does exist suggests that no NOx reductions would be achieved. In contrast to this uncertain NOx reduction, there is a real potential for creating adverse side effects which would be accompanied by reduced unit availability and reliability. There is thus no certainty that the retrofit of OFA to a boiler with an integrated low-NOx burner/boiler design will achieve emission levels any lower than 0.550 lb/MBtu and, in fact, use of OFA might produce higher emissions and may well have severe adverse side effects.

4.4 LOW EXCESS AIR OPERATION

Minimization of excess air is always an objective of utility boiler operation because, in addition to minimizing NOx emissions, it maximizes fuel efficiency--provided low excess air does not cause other problems. It is the other constraints which need to be explained in order to understand why there are limits to the minimization of excess air.

Perhaps the most important parameter affecting a boiler's combustion operating margin is excess air. However, it is very difficult to design pulverized coal-fired boilers to operate at an exact excess air level because of the variable characteristics of most coal. This normal variation can be seen in the IPP coal data presented in Appendix D. As a result, necessary means for controlling unexpected problems such as steam temperature deficiencies, slagging conditions, and combustion anomalies must be incorporated into a boiler design. Excess air is one of the most important means for controlling such problems. A boiler manufacturer designs the boiler to operate at certain levels of excess air at various load settings. The design excess air level, however, is not the minimum excess air level at which the boiler could operate because some margin must be added to account for variations (e.g., fuel heating value) that could be experienced. Figure 4-5 conceptually illustrates the difference between minimum and design excess air levels.

Each boiler has its own characteristic carbon monoxide (CO) and/or opacity curve. As excess air is lowered, a point is reached where any further lowering of the excess air produces excessively high levels of CO and/or carbon in fly ash, and usually opacity. This point is referred to as the minimum excess air level. Since this point usually results in minimizing the stack gas heat losses, it is also commonly referred to as the optimum excess air level. If steady boiler operation could be maintained and if no variations in fuel, operating parameters, etc. were encountered, the optimum excess air level could be maintained provided no adverse effects such as slagging were to occur. This is an ideal situation, but one which is seldom possible in actual operation. Therefore, the design excess air level is established somewhat higher to account for variations that will be experienced.

A boiler's design excess air level is for one specific coal type, the coal which dictates the boiler design. When the boiler is operating normally with the design coal type, the design excess air levels can be maintained. It is clear that if a boiler's NOx emissions were near the regulated limits under conditions of normal operation, the operating margin could be substantially reduced during times when unexpected operational difficulties are encountered that require increases in excess oxygen. This is due to the fact that increases in excess air to control such difficulties would increase the NOx emission which in turn might be the limiting factor at certain operating loads. Some of the unexpected operational differences might include the following:

1. Slagging - When coal ash properties are unfavorable due to normal variations in properties in various parts of a coal seam, partly melted ash can form sticky deposits on boiler tubes. These deposits sometimes cannot be removed during operation, and continue to accumulate until the boiler must be brought out of service and the cold, rock-hard slag deposits removed using dynamite and fire hoses. Raising excess air level is often the most important method of avoiding such serious slagging incidents. In these circumstances, excess air is needed to eliminate localized fuel-rich atmospheres which encourage the melting of the ash.
2. Load swings - Some units are operated as cycling units at some point in their lifetime; i.e., their load varies with system demand. This mode of operation necessitates that higher excess air levels be maintained to allow for rapid changes in fuel flows without leading to potentially unsafe furnace conditions.
3. Combustion equipment deterioration - Pulverizers (mills) continually become worn between refurbishments and this affects the coal size distribution going to the burners. Higher levels of excess air are required to maintain complete combustion until the reason for the variation is identified and corrected.

These are just a few of the operational variations that might be experienced, and are presented here to illustrate that design excess air levels cannot always be maintained. The EPA is apparently aware of the importance of excess air as an operational tool, as the following statement from their "Control Techniques for Carbon Monoxide Emissions" report (Ref. 30) states:

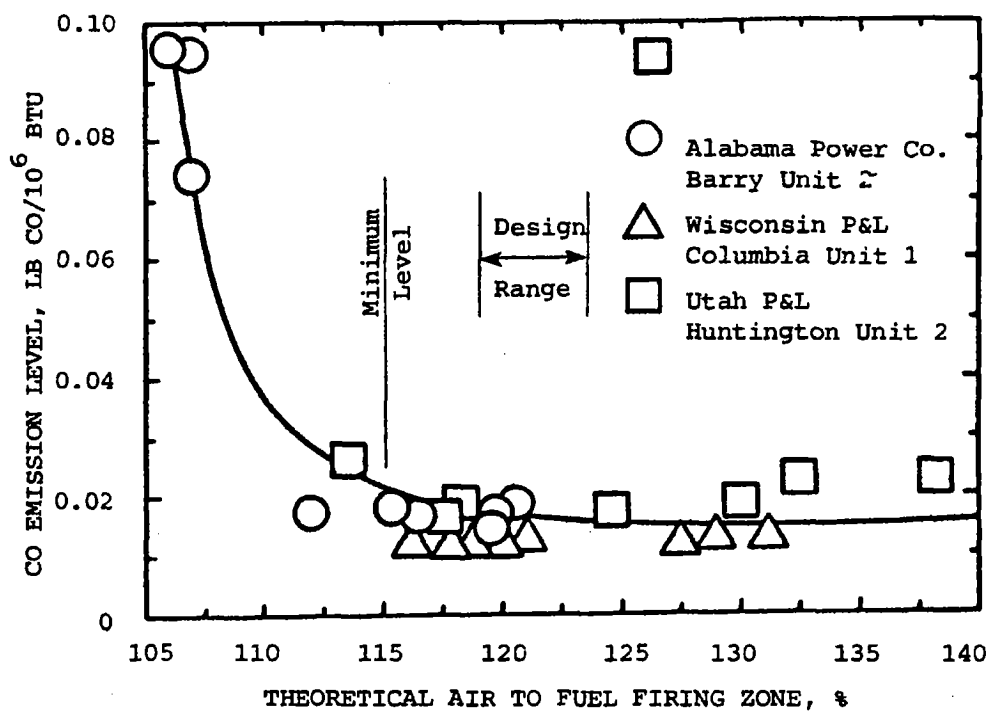


Figure 4-5. Design vs. minimum excess air on coal-fired boilers.

"It is desirable to operate combustion equipment at the lowest possible excess air level that does not cause excessive CO or smoke emissions. In general, this will result in maximum fuel efficiency and minimum NOx emissions (in the absence of other NOx control measures). However, it is necessary to operate at excess air levels which are slightly higher than the optimum level to provide a cushion against variations in process conditions. That is, it is difficult to maintain the proper air/fuel ratio due to variations in the fuel heating value, ambient temperature and pressure, or fuel flow rates. Without such a cushion, fluctuations in the air/fuel ratio will result in periodic smoke and/or high CO emissions.

"Environmental Effects - Excess air rate adjustment for CO control can result in increased NOx emissions. Unfortunately, the conditions most favorable for low CO emissions, i.e., sufficient oxygen for ample mixing for complete combustion at high flame temperatures, tend to produce high NOx emissions. NOx control techniques, which rely on reducing the maximum flame temperature and limiting the availability of oxygen in the flame tend to result in increased CO emissions. Consequently, reduced excess air rates, or other NOx control methods, are generally applied to the point where flue gas CO concentrations approach 200 ppm."

While these comments discuss in general the concerns of low excess oxygen operation in terms of increased CO emissions, in most cases unburned carbon is the major problem with coal-fired boilers. There is no general correlation of carbon formation with respect to excess oxygen level; however, it generally follows the same trends as CO versus excess oxygen--decreasing excess oxygen increases carbon formation. As mentioned in Section 4.3.1, the baghouse supplier for IPP indicates that increased carbon in the fly ash could decrease the life of the bags as well as the collection efficiency.

In summary, low excess air operation, within necessary practical constraints, is an integral part of the IPP boilers' present design for both NOx control and efficiency. To take advantage of the effects of low-excess-air operation, the low-NOx burners are designed to operate at the lowest practical level consistent with good operation and prevention of adverse side effects. Low-excess-air operation is therefore already in place when these low-NOx burners are utilized, and consequently is already part of the BACT strategy at IPP. Attempts to lower the excess air levels further could seriously limit the ability of the operators to solve normal day-to-day problems. This would eventually create an availability or reliability problem.

4.5 DECREASED PLAN HEAT RELEASE THROUGH BOILER DERATING

Each individual boiler exhibits its own individual NOx emission characteristics vs. load. This is primarily due to the mode of operation necessary to ensure proper steaming characteristics over the load range. This is illustrated in Figure 4-6 which shows the NO characteristics of four individual boilers (Ref. 31). These data were extracted from an EPA program to assess the 30-day rolling average NO data from a number of NSPS design boilers firing pulverized coal. As can be seen, the NOx emission from various boilers can exhibit widely varying NOx characteristics ranging from near steady NOx vs. load characteristics to NOx decreases with increasing load. These NOx characteristics cannot be determined in the design stage. Even use of data from a sister unit can be misleading when attempting to extrapolate to a unit in design. Figure 4-7 (Ref. 30) illustrates the wide variation in NO characteristics between two apparently identical units. The characteristics of a boiler can only be determined from operating data after the unit has completed its commercial startup.

Since units are designed to operate at their maximum load point, reductions in load to achieve a reduction in NOx emissions greatly affects the economics of operation. For a unit already in construction, the penalties would be significant. One penalty would be due to operation over the boiler lifetime (35 years) at efficiencies less than the design efficiency at maximum load. This would be an effective increase in fuel costs which would be sustained for the life of the boiler. A major penalty would be the cost of wasted capital resulting from lost generation capability built into the unit and not used. In addition to this wasted capital cost, the lost revenue associated with the unused generating capacity would be substantial.

In summary, there is no method to predict the NOx vs. load characteristics of the unit designed for IPP without actual testing. A decision to reduce the maximum capacity of the unit before completion could result in restricting the units to operation at higher NOx emission rates than would be experienced at the design load. Load reduction as a technique for reducing NOx on a unit in design has not been considered a control technology in the past. In view of the uncertainty in predicting the effect of a load reduction, and the fact that load reduction is not a technique devised since

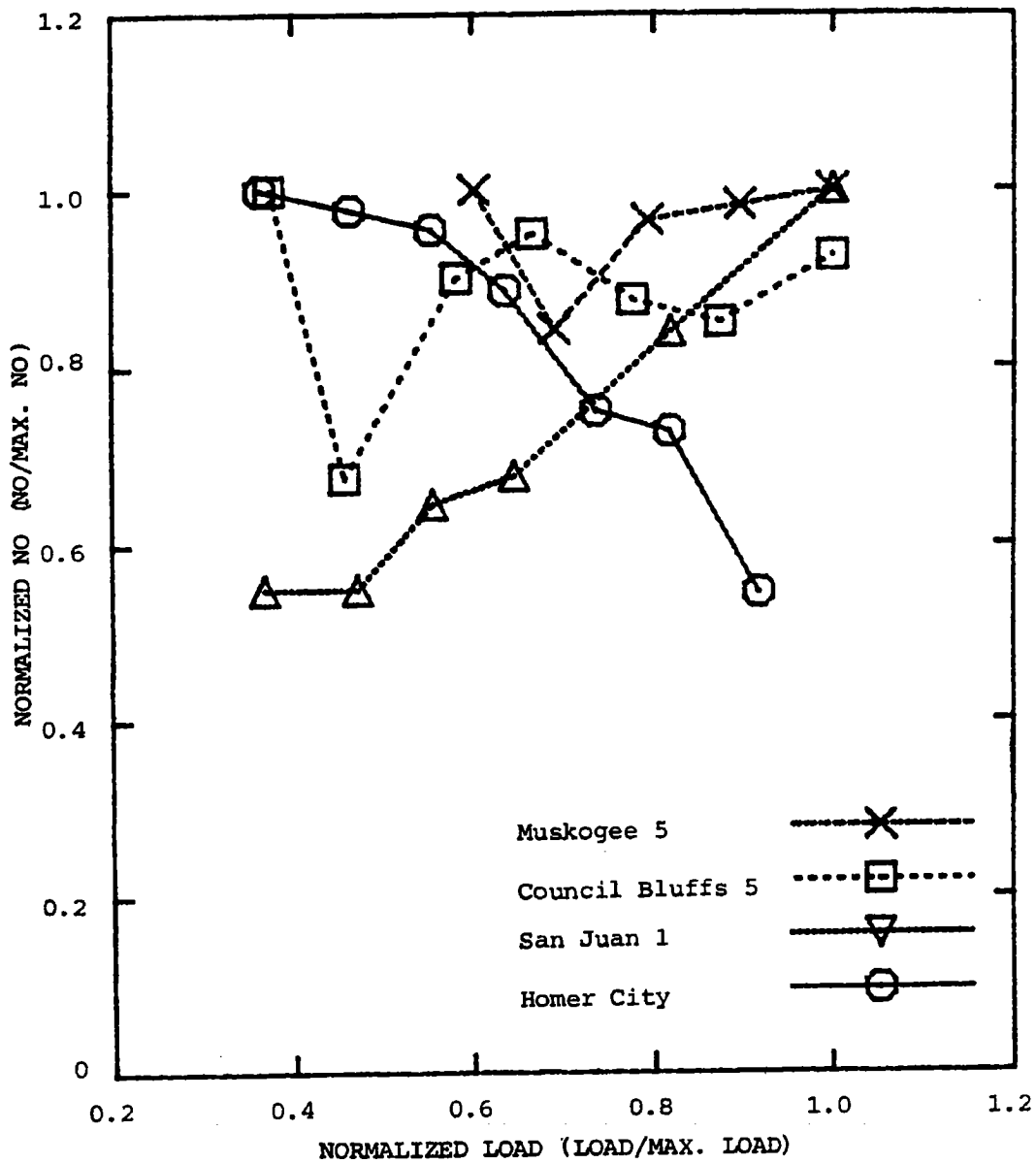


Figure 4-6. NO characteristics of typical utility boilers (Ref. 31).

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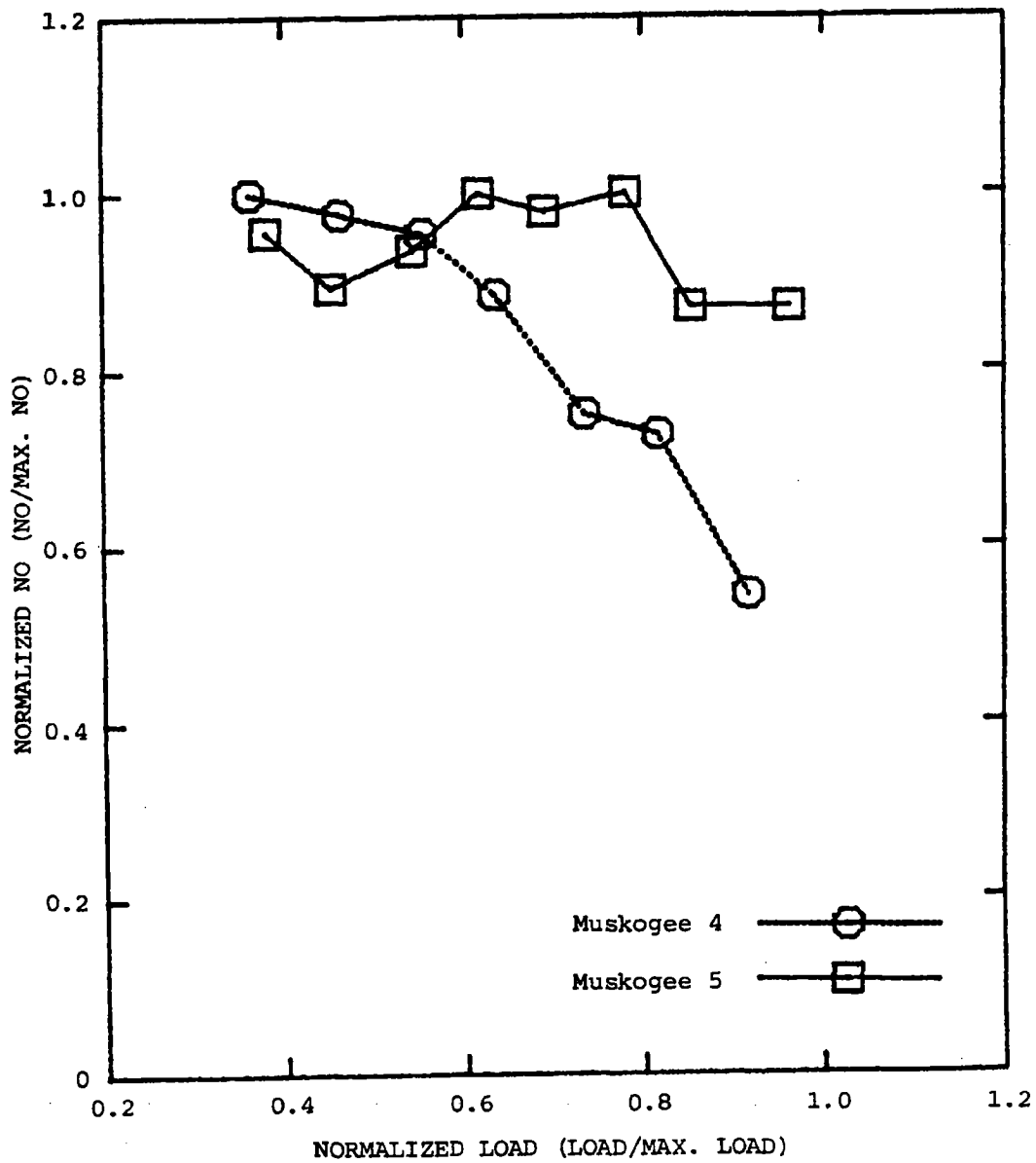


Figure 4-7. Comparison of OGE, Muskogee Units 4 and 5, NO characteristics (Ref. 31).

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the IPP permit was issued, it should not now be considered a new control technology for the purpose of BACT review.

SECTION 5.0

CONCLUSIONS

Based on the technical analyses described in this report, the following conclusions are drawn:

1. The SCR process has not been demonstrated to be effective at large scale either in systems using a baghouse, or on coals containing the catalyst poisons sodium, potassium, and calcium in the quantities present in Utah bituminous coals. The reliability and availability of the backend cleanup devices would be seriously jeopardized with the installation of an SCR. The SCR process has therefore not been developed to the point where, if applicable to IPP, there is any certainty that it could achieve reliable, continuous reductions in NOx emissions.
2. Thermal DeNOx is an experimental technology on coal and has never been demonstrated to be effective on a coal-fired utility boiler. Therefore it should not be considered for application at IPP.
3. There is insufficient long-term data to justify the risk of retrofit of overfire air ports to accomplish an uncertain NOx reduction in view of the potential for creating adverse side effects. There is a risk that retrofit of OFA could jeopardize the availability and reliability of the boiler as well as the baghouse. The low-NOx burner system incorporated into the present IPP design is capable of yielding low NOx without these adverse side effects.
4. The burner system used by the boiler manufacturer on the IPP boilers incorporates low-NOx burners that operate at the lowest practical excess air levels. These burners are proven in use on the type of boiler to be built for IPP. No combustion technology is available for achieving further reductions in excess air without causing unacceptable side effects such as slagging, reduced steam temperature, and loss of fuel efficiency. Further reduction in excess air levels is therefore not practical.

5. Decreased plan heat release through boiler derating has not been consistently demonstrated to yield consistent NOx reductions, and in any case, cannot be considered new technology for the purpose of BACT review.
6. The current boiler design incorporates the latest demonstrated reliable NOx control techniques. This integrated system incorporates a generous heat release area and low-NOx burners which operate at low excess air levels. The system is designed to operate reliably without adverse side effects while achieving NOx emissions no greater than 0.55 lb/MBtu. It is the opinion of KVB that there are no changes that could be made in the boiler design that will ensure any lower NOx emission levels could be achieved on a long-term basis at IPP.

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APPENDIX A

COMBUSTION CONTROL OF NOx

A.1 NOx FORMATION AND DESTRUCTION MECHANISMS

Oxides of nitrogen formed in combustion processes are due either to the thermal fixation of atmospheric nitrogen in the combustion air which produces "thermal NOx", or to the conversion of chemically bound nitrogen in the fuel which produces "fuel NOx." For natural gas and light distillate oil firing, nearly all NOx emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and, in certain cases, predominant.

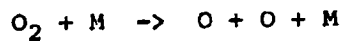
A.1.1 Thermal NOx

During combustion, nitrogen oxides are formed by the high temperature, thermal fixation of N_2 . Nitric oxide (NO) is the major product, even though NO_2 is thermodynamically favored at lower temperatures. The residence time in most stationary combustion processes is too short for significant NO to be oxidized to NO_2 .

The detailed chemical mechanism for thermal NOx formation is not fully understood. However, it is widely accepted that thermal fixation in the post-combustion zone occurs according to the extended form of the Zeldovich chain mechanism:



assuming that the combustion reactions have reached equilibrium. Reaction (1) has a large activation energy (317 kJ/mol) and is generally believed to be rate determining. Oxygen atom concentrations are assumed to have reached equilibrium according to:



(4)

where M denotes any third substance (usually N_2).

In the flame zone itself, the Zeldovich mechanism with the equilibrium oxygen assumption is not adequate to account for experimentally observed NO formation rates. Several investigators have observed the production of significant amounts of "prompt" NO, which is formed very rapidly in the flame front (Refs. A-1 through A-9) but there is no general agreement on how it is produced. Prompt NO is believed to stem from the existence of "superequilibrium" radical concentrations (Refs. A-9 through A-11) within the flame zone which result from hydrocarbon chemistry and/or nitrogen specie reactions, such as suggested by Fenimore (Ref. A-12). To date, prompt NO has only been explicitly measured in carefully controlled laminar flames, but the mechanism almost certainly exists in typical combustor flames as well. In an actual combustor, both the hydrocarbon and NOx kinetics are directly coupled to turbulent mixing in the flame zone.

Experiments at atmospheric pressure indicate that under certain conditions, the amount of NO formed in heated N_2 , O_2 , and air mixtures can be expressed as (Ref. A-13):

$$[\text{NO}] = k_1 \exp(-k_2/T) [\text{N}_2] [\text{O}_2]^{1/2} t \quad (5)$$

where [] = mole fraction

k_1, k_2 = constants

T = temperature

t = time.

Although this expression does not adequately describe NO formation in a turbulent flame, it points out several features of thermal NOx formation. It reflects the strong dependence of NO formation on temperature. It also shows that NO formation is directly proportional to the square root of oxygen concentration.

Based on the above relations, thermal NOx can theoretically be reduced using four tactics:

- o Reduce local nitrogen concentrations at peak temperatures
- o Reduce local oxygen concentrations at peak temperature
- o Reduce the residence time at peak temperature
- o Reduce the peak temperature

Since reducing N_2 levels is quite difficult, efforts have focused on reducing oxygen levels, peak temperatures, and time of exposure in the NO_x-producing regions of a furnace. Techniques such as lowered excess air and off-stoichiometric (or staged) combustion have been used to lower local O_2 concentrations in utility boilers. Similarly, flue gas recirculation and reduced air preheat have been used on gas- and oil-fired boilers to control thermal NO_x by lowering peak flame temperatures. Flue gas recirculation also reduces combustion gas residence time, but its primary effect as a thermal NO_x control is through temperature reduction. Flue gas recirculation has not been very successful in reducing NO_x on coal-fired boilers, primarily because it does not substantially affect fuel NO_x.

It is important to recognize that the above-mentioned techniques for thermal NO_x reduction alter combustion conditions. Although these techniques have all been relatively successful in reducing thermal NO_x, local combustion conditions ultimately determine the amount of thermal NO_x formed. These conditions in turn are intimately related to such variables as local combustion intensity, heat removal rates, and internal mixing effects. Modifying these secondary combustion variables requires fundamental changes in combustion equipment design.

Recent studies (Refs. A-14, A-15) on the formation of thermal NO_x in gaseous flames have confirmed that internal mixing can have large effects on the total amount of NO formed. Burner swirl, combustion air velocity, fuel injection angle and velocity, quarl angle, and confinement ratio all affect the mixing between fuel, combustion air, and recirculated products. Mixing, in turn, alters the local temperatures and specie concentrations which control the rate of NO_x formation.

Generalizing these effects is difficult because the interactions are complex. Increasing swirl, for example, may both increase entrainment of cooled combustion products (hence lowering peak temperatures) and increase fuel/air mixing (raising local combustion intensity). The net effect of increasing swirl can be either to raise or lower NO_x emissions, depending on other system parameters.

The hierarchy of effects depicted in Table A-1 produces local combustion conditions which promote thermal NOx formation. Although combustion modification technology seeks to effect the fundamental parameters of combustion, modifications must be made by changing the primary equipment and fuel parameters. Control of thermal NOx, which began by altering inlet conditions and external mass addition, has moved to more fundamental changes in combustion equipment design.

TABLE A-1. FACTORS CONTROLLING THE FORMATION OF THERMAL NOx (Ref. A-16)

Primary Equipment and Fuel Parameters	Secondary Combustion Parameters	Fundamental Parameters	
Inlet temperature, velocity			
Firebox design	Combustion intensity		
Fuel composition	Heat removal rate	Oxygen level	
Injection pattern of fuel and air	Mixing of combustion products into flame	Peak temperature	Thermal NOx
Size of droplets or particles	Local fuel/air ratio	Exposure time at peak temperature	
Burner swirl	Turbulent distortion of flame zone		
External mass addition			

A.1.2 Fuel NOx

Fuel-bound nitrogen occurs in coal and petroleum fuels. However, the nitrogen-containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation (Ref. A-17). Therefore fuel NOx is of importance primarily in residual oil and coal firing. The nitrogen compounds found in petroleum include pyrroles, indoles, isoquinolines, acridines, and porphyrins. Although the structure of coal has not been defined with certainty, it is believed that coal-bound nitrogen also occurs in aromatic ring structures such as pyridine, picoline, quinoline, and nicotine (Ref. A-17).

The nitrogen content of residual oil varies from 0.1 to 0.5 percent. Nitrogen content of most U.S. coals lies in the 0.5% to 2% range (Ref. A-18). Thus fuel NO_x is a primary concern of coal combustion.

Although the precise mechanism by which fuel nitrogen in coal is converted to NO_x is not understood, certain aspects are clear. In a large pulverized coal-fired utility boiler, the coal particles are conveyed by an air stream into the hot combustion chamber, where they are heated at a rate in excess of 10^4 °R/s. Almost immediately, volatile species containing some of the coal-bound nitrogen vaporize and burn homogeneously, rapidly (approx. 10 milliseconds), and probably detached from the original coal particle. Combustion of the remaining solid char is heterogeneous and much slower (approx. 300 milliseconds). Nitric oxide can be produced from either the volatile or char fraction of the coal.

Figure A-1 summarizes what may happen to fuel nitrogen during this process. In general, nitrogen volatile evolution parallels evolution of the total volatiles except during the initial 10% to 15% volatilization in which little nitrogen is released (Ref. A-16). Both total mass volatilized and total nitrogen volatilized increase with higher pyrolysis temperature; the nitrogen volatilization increases more rapidly than that of the total mass. The relationship between total mass devolatilized and weight percent nitrogen devolatilized is shown by Figure A-2. Figure A-2 also shows that char devolatilizes nitrogen at a lower rate than coal. Pyrolysis temperatures can influence the split between volatile and char NO. However, at temperatures greater than 1800°K, the char would be devoid of nitrogen, and char-produced NO would not exist.

Coal type, as well as pyrolysis temperature, are important in determining the amount of nitrogen devolatilized. Figure A-3 illustrates the relationship for four different coals. For a given temperature, differences of up to 30% in volatile nitrogen yield can be seen. Thus, NO_x emissions may be different from coals with the same nitrogen content.

Although there is no absolute agreement on how the volatiles separate into species, it appears that about half the total volatiles and 85% of the nitrogenous species evolved react to form other reduced species before being oxidized. Prior to oxidation, the devolatilized nitrogen may be converted to a small number of common, reduced intermediates such as HCN and NH in the fuel

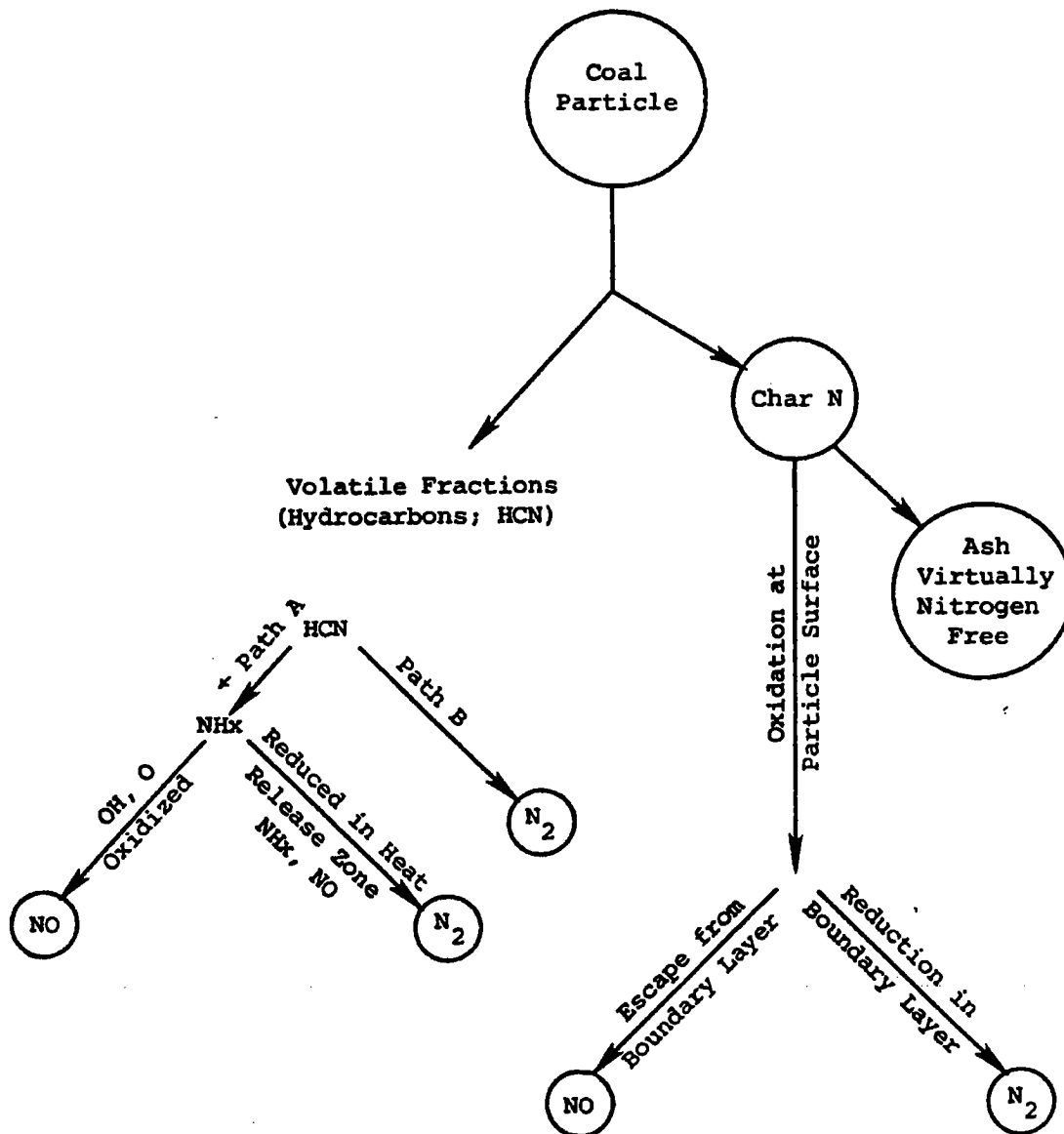


Figure A-1. Possible fate of fuel nitrogen contained in coal particles during combustion (Refs. A-16, A-19, A-20).

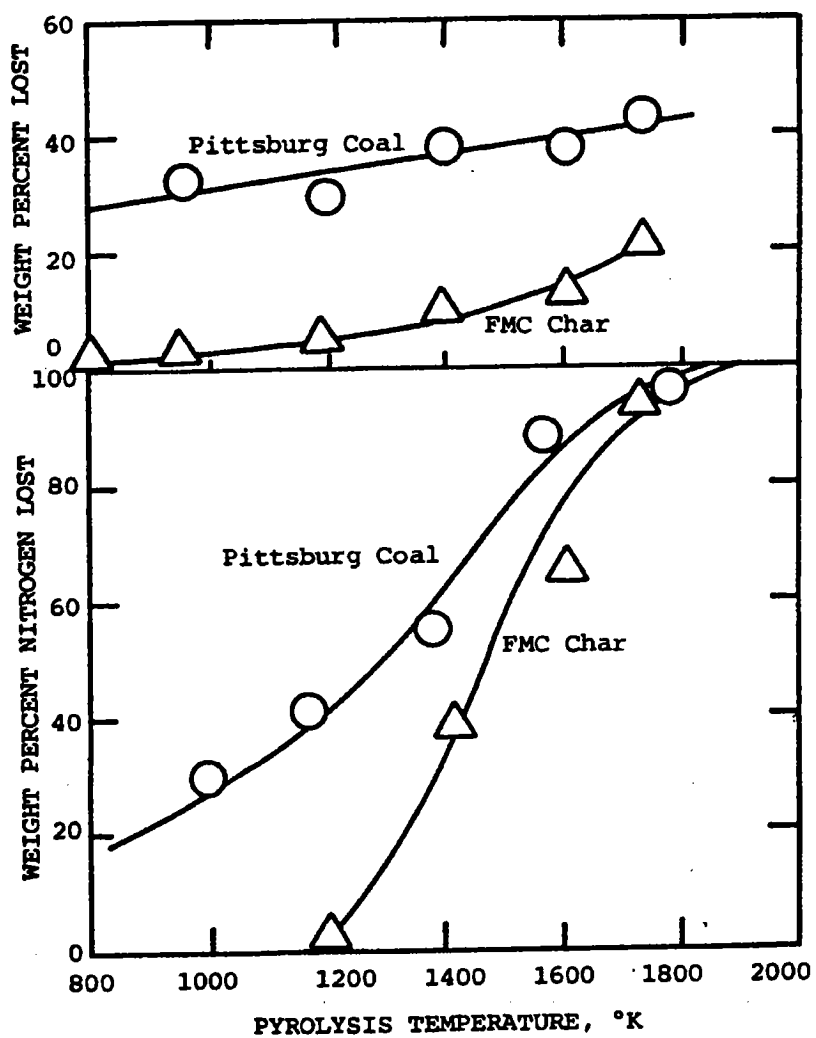


Figure A-2. Devolatilization yields for coal and a coal char (Ref. A-19).

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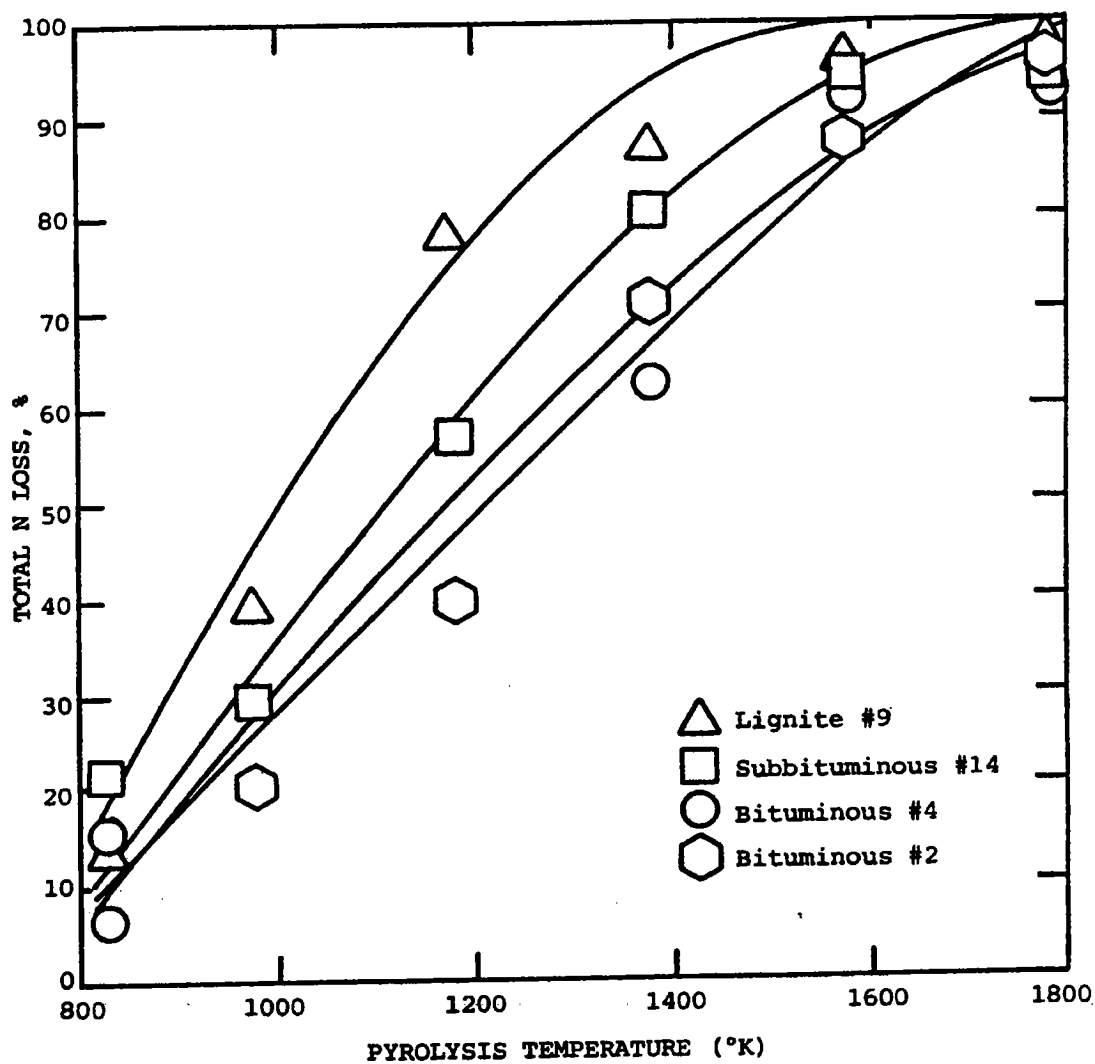


Figure A-3. Influence of coal composition and pyrolysis temperature on nitrogen yields (Ref. A-19).

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rich regions of the flames. The existence of a set of common reduced intermediates would explain the observation that the form of the original fuel nitrogen compound does not influence its conversion to NO. Recent experiments suggest that HCN is the predominant reduced intermediate (Ref. A-20). The reduced intermediates are then either oxidized to NO or converted to N_2 in the post combustion zone. Although the mechanism for these conversions is not presently known, one proposed mechanism postulates a role for NH_x and NO (Refs. A-19, A-20). Nitrogen retained in the char may also be oxidized to NO, or reduced to N_2 through heterogeneous reactions occurring in the post combustion zone. The fraction of nitrogen remaining in the char can be high, although its conversion to NO is low compared to volatile nitrogen conversion to NO. This is probably due to the mechanism of char combustion. It is believed that char combustion involves internal burning with diffusion at or in the particulate a controlling parameter. Because of the nature of char combustion, the conversion of nitrogen in the char to NO is not affected by near-burner aerodynamics. Thus, char NO can have significance in terms of ultimate ability to reduce NO emissions.

Based on experimental and modeling studies, it is believed that 60% to 80% of the fuel NOx results from volatile nitrogen oxidation. Conversion of char nitrogen to NO is generally lower, by factors of two or three, than conversion of total coal nitrogen, but is also relatively insensitive to load or overall stoichiometry.

Regardless of the precise mechanism of fuel NOx formation, several general trends are evident. Fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment, as shown in Figure A-4. Oxidation of the char nitrogen is relatively insensitive to fuel/air changes, but volatile NO formation is strongly affected by fuel/air ratio changes. Thermal nitrogen is also affected by the fuel/air ratio. The effect of fuel/air ratio on the relative contribution of each form of NO (thermal, char, and fuel) can be seen in Figure A-5.

In contrast to thermal NOx, fuel NOx production is relatively insensitive to small changes in combustion zone temperature (Ref. A-22). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage

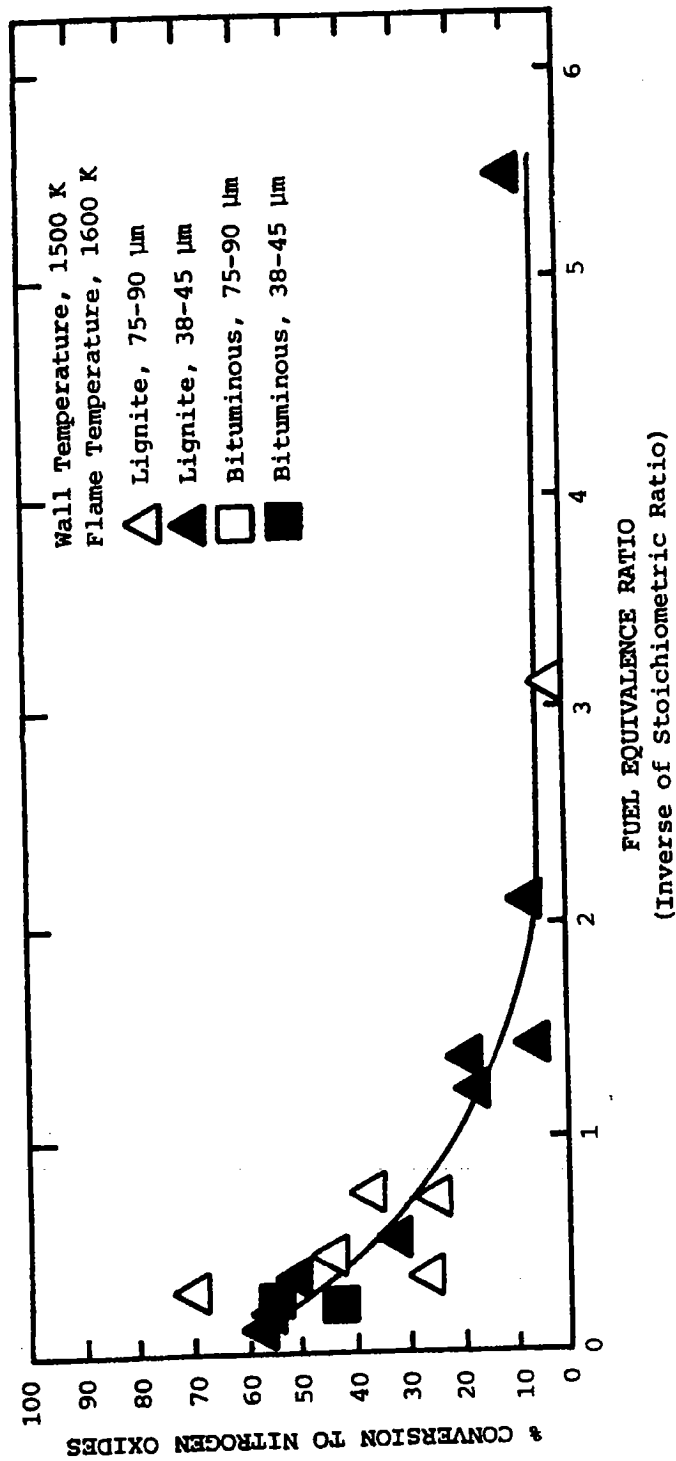


Figure A-4. Conversion of nitrogen in coal to NOx (Ref. A-21).

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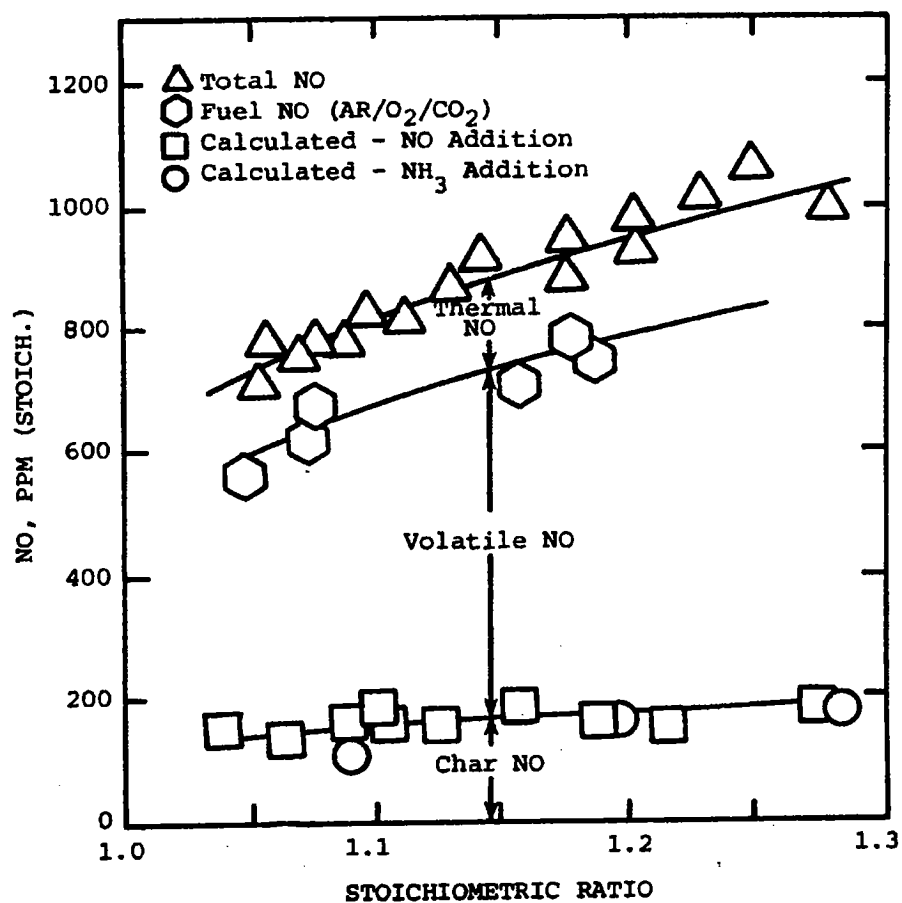


Figure A-5. Sources of NOx emissions in turbulent-diffusion pulverized-coal flames. Wall-fired simulation: Western Kentucky coal (Ref. A-22).

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conversion. Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

Fuel NOx emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal volatilization will dramatically increase volatile nitrogen conversion and increase fuel NOx. In contrast, char NO formation is only weakly dependent on initial mixing.

From the above modifications, it appears that, in principle, the best strategy for fuel NOx abatement combines low excess air (LEA) firing, optimum burner design, and two-stage combustion. Assuming suitable stage separation, LEA may have little effect on fuel NOx, but it increases system efficiency. Before using LEA firing, the need to get good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of devolatilized nitrogen to N_2 . Two-stage combustion produces overall fuel-rich conditions during the first one to two seconds and promotes the reduction of NO to N_2 through reburning reactions. High secondary air preheat may also be desirable, because it promotes more complete nitrogen devolatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates.

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APPENDIX B

ADVERSE EFFECTS OF LOW-NOx OPERATION

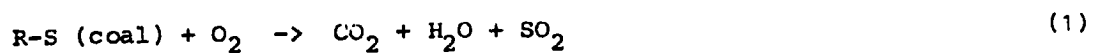
Altering combustion conditions in order to reduce NOx formation could potentially lead to increased levels of corrosion, fouling, and/or slagging. These potential problems are strongly related to coal ash characteristics and are also influenced by other operating conditions. It is important to understand all contributing factors in order to assess the potential for low-NOx combustion conditions to lead to severe levels of corrosion, fouling, and/or slagging.

B.1 CORROSION

This section will focus on external corrosion of furnace and high-temperature convective tubes since corrosion in these zones is most closely related to combustion conditions.

B.1.1 Furnace Tube Corrosion

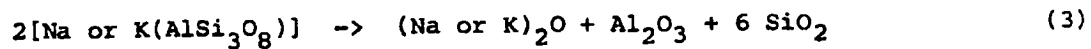
There are two principal types of corrosion that affect furnace tubes: alkali sulfate and iron sulfide attack. The mechanism of alkali sulfate attack involves the action of active (volatile) sodium and potassium in the coal reacting with sulfur trioxide to form alkali sulfates. The alkali sulfates react in the presence of SO₃, breaking down the protective oxide layer on the furnace tubes. The mechanism is shown below (Ref. B-1):



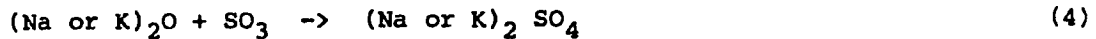
Evolution of sulfur dioxide



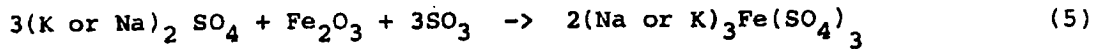
Formation of sulfur trioxide



Evolution of alkali oxides



Formation of alkali sulfates

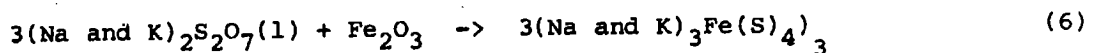


Reaction of alkali sulfate with protective oxide layer

The products of reaction (5) tend to slow down the corrosion rate, but if the deposit spalls, fresh metal is exposed and the process is repeated.

Iron pyrites (FeS_2) are also associated with alkali sulfate corrosion. Fifty to seventy-five percent of the sulfur in coal appears as pyritic sulfur, virtually all of the iron found in coal ash is in the form of pyrites (Ref. B-8). Operational conditions creating flame impingement and poor coal/air mixing can lead to deposition of pyrites in the vicinity of the alkali metal sulfates described above. The pyrites can then oxidize to FeS and Fe_3O_4 , thereby producing SO_3 in the vicinity of the tube, which increases the rate of reaction (5) and thereby accelerates the corrosion process.

A more extreme corrosion reaction can occur if there is a particularly high ratio of potassium to sodium in the furnace wall deposits. In this case, SO_3 and the alkali sulfate mixture can form a liquid pyrosulfate, which attacks the protective oxide layer at a much higher rate than in the dry reaction [reaction (5)], again forming a complex alkali-ferric trisulfate (Ref. B-8):



Corrosion can also take place due to sulfide attack. This typically occurs during fuel-rich combustion (staging or air maldistribution). Fuel-rich combustion tends to increase peak flame temperature and leads to ash deposition as a result of the higher temperatures and a reduction in the ash fusion temperature. In this oxygen-deficient environment, the sulfur from the decomposition of pyrites in the coal and ash will not be fully oxidized to sulfur dioxide. In the presence of unburned carbon or low excess air, pyrites on furnace tubes are reduced to elemental sulfur, which can then react directly with the metal to form iron sulfide (Ref. B-10):



(7)

The presence of FeS in the deposits found on badly corroded furnace tubes has been reported in the literature (Ref. B-10). Carbon was also found in some of the deposits, indicating that normal oxidation had not occurred.

Additional evidence for this mechanism was obtained when corrective measures were applied to furnaces experiencing severe corrosion in areas with FeS deposits. Both the rapid corrosion and the FeS were eliminated when repairs were made to ensure that the sulfur and the carbon would be completely oxidized before reaching the furnace water tubes (Ref. B-10).

Sulfide corrosion is particularly serious when the tube metal contains nickel since the corrosion propagates along the grain boundaries. The resulting nickel sulfides are low melting compounds, and being liquids of more than one valence state can transport sulfur from the edge of the grain boundary deep into the metal (Ref. B-11).

Corrosion can be especially serious when the furnace environment fluctuates between reducing and oxidizing as can occur along the boundaries of fuel-rich zones under staged combustion or with fuel/air maldistribution. Incomplete combustion of carbon in a fuel-rich zone will result in an increase in CO concentration. CO will reduce the thickness of the oxide layer on furnace tubes, exposing fresh iron to oxidation attack and/or accelerated corrosion by sulfur via the mechanism presented earlier.

The reduction sequence $\text{Fe}_2\text{O}_3 \rightarrow \text{Fe}_3\text{O}_4 \rightarrow \text{FeO}$ can occur when the ratio of CO to CO_2 is 1:1. Furthermore, the CO can react with FeO to form iron carbides (Fe_3C) which forms a thin scale that is easily removed (Ref. B-12).

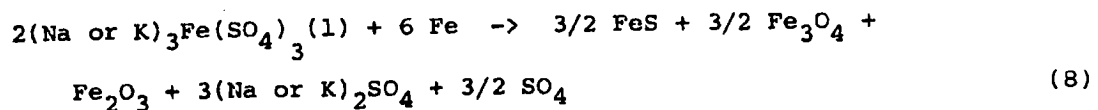
Excessive loss of tube metal in large steam-generators in this country and in Europe has been attributed to an environment that fluctuates between oxidizing and reducing (Refs. B-10, B-11, B-13, B-14). At a steam generator in Munich, Germany, furnace tubes subject to flame impingement and alternate oxidizing and reducing atmospheres decreased in thickness from 32 mm to 1.8 mm in 3500 hours (i.e., 138 mils per year), requiring the replacement of over 100 tubes (Ref. B-11).

B.1.2 High Temperature Corrosion

Corrosion of the tubes in the convective region of the boiler occurs mainly in the regions of highest metal temperatures when ferritic and austenitic steels are used. Carbon steel is used in the low temperature regions of the superheater and reheater. As tube metal temperatures increase, ferritic and austenitic steels are used. Ferritic steel is used for tube metal temperatures (outside wall) from 1075°F to 1100°F. Above 1100°F (outside wall), austenitic steel is used. Ferritic is a low carbon (0.1%) stainless that contains 5% to 30% chrome and no nickel. Austenitic is also a low carbon (0.08%) stainless that contains 16% to 26% chrome and 6% to 22% nickel.

Both austenitic and ferritic steels are subject to liquid phase attack by complex sulfates. The wastage of ferritic steels increases with increasing temperature up to 1100°F, the limit of their useful range. The effect of temperature on wastage of austenitic steel is characterized by a "bell-shaped" curve as shown in Figure B-1. Figure B-1 also shows the roles of the complex sulfate compounds necessary to form corrosive superheater deposits. The sulfate complexes are unstable above 1300°F and are not molten below 1025°F, thus corrosion would not be expected outside of this temperature range.

The corrosive reaction on superheater and reheater tubes is similar to the reactions for furnace tubes--alkali sulfates, iron oxide, and SO_3 react to form alkali-ferric trisulfate as per reaction (5). Although the alkali-ferric trisulfate is a solid at furnace tube metal temperatures, at the higher tube metal temperatures of the superheater and reheater the complex sulfate is molten. This molten complex sulfate can attack the tubes directly (Ref. B-8):



The ratio of sodium to potassium influences the temperature at which the alkali-ferric trisulfate is molten. Typically, coal ash has a Na:K ratio of 1:2 and fly ash 1:4. As the ratio of sodium to potassium increases, the temperature range for which the deposit is molten increases. The maximum molten range, and consequently the most corrosive condition, occurs at a sodium to potassium range of 1:1 as illustrated in Figure B-1.

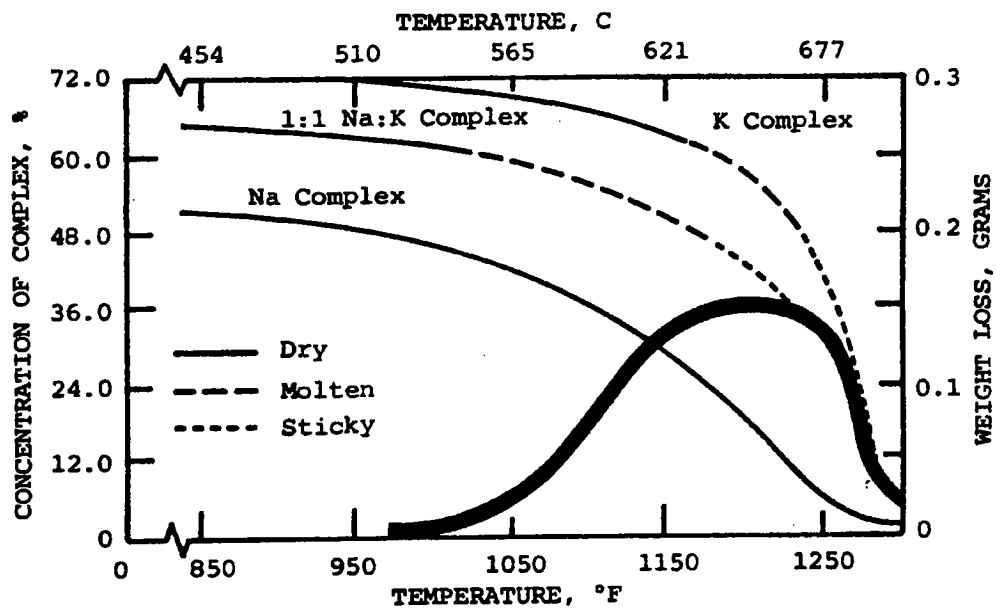
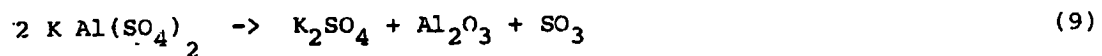


Figure B-1. Physical state of complex sulfates as a function of temperature and the corrosion of austenitic alloys (Ref. B-8).

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Corrosion by sulfide attack can also occur on superheater and reheater tubes. The corrosive mechanism is the same: $\text{Fe (tube metal)} + \text{S} \rightarrow \text{FeS}$. One proposed sequence for this corrosion involves the condensation and deposition of volatile sodium and potassium compounds released during combustion. Unburned coal and pyrites due to severe flame carryover or incomplete combustion, adhere to the condensed alkalis. The pyrites and coal then evolve sulfur, which attacks the tube metal directly (Ref. B-10).

The presence of $\text{KAl(SO}_4)_2$ in corrosive deposits has been reported (Refs. B-10 and B-13). These deposits contain no sulfides. The following reaction is believed to occur:



In order for this reaction to occur to an appreciable rate; however, base metal must be exposed.

Various methods of combatting high temperature corrosion have been used or suggested, including the following (Ref. B-15):

- o Coal selectivity and the grinding of coals to a finer size.
- o Improved combustion conditions; i.e., fast ignition, good mixing, and proper excess air.
- o Use of more corrosion-resistant alloys.

B.2 FOULING

Fouling refers to bonded deposits occurring in the convective heat transfer zones, especially reheater and superheater surfaces. Several types of bonded deposits have been identified, including alkali (primarily sodium and potassium), calcium, phosphorous, and silica. Alkali and calcium bonded deposits are the most common, with the alkali type being the more predominant of the two.

B.2.1 Fouling Mechanisms

Fouling is believed to due mainly to volatilization of alkali metals and/or alkali compounds in the furnace followed by recondensation on tubes in the convective section. The degree to which these alkali metals and their compounds volatilize depends on the firing conditions and the forms in which they are present in the coal. Figure B-2 illustrates the different forms in which the various alkali metals can be present. These alkali metals are contained in a heterogeneous mixture in the coal particle. The more active alkalis originate as either inorganic salts or organically bound alkali. Volatilization of these alkalis is also dependent on time and combustion temperature. Combustion temperature, in turn, is affected by heat release rate, firing method, excess air, and combustion air temperature

The volatilized alkalis react with SO_2 and SO_3 to form complex alkali sulfate. Table B-1 lists some typical compounds formed and their melting temperatures.

One of the main variables influencing fouling is furnace exit temperature. High flue gas temperatures at the furnace exit result in correspondingly higher temperature levels throughout the convective pass section and will result in increased deposits. As the layer of alkali sulfates grows in thickness, heat transfer to the tubes decreases, and the outermost layer becomes increasingly hot. Eventually, it becomes sticky and collects dry fly ash by impaction on the upstream side of the tubes.

If the flue gas temperature is sufficiently high, a molten phase will eventually form at the leading edge of the deposit and begin to collect fly ash particles on impact and form a strong bulk deposit. If the flue gas temperature is excessive, further collection and accumulation of fly ash particles will lead to tube bundle blockage.

Increased fouling was experienced by a midwestern utility firing lignite under low-NOx operating modes (low excess air and overfire air). Under the low-NOx operating conditions, fouling significantly increased. This was believed to be the result of increased furnace exit temperature (Ref. B-17).

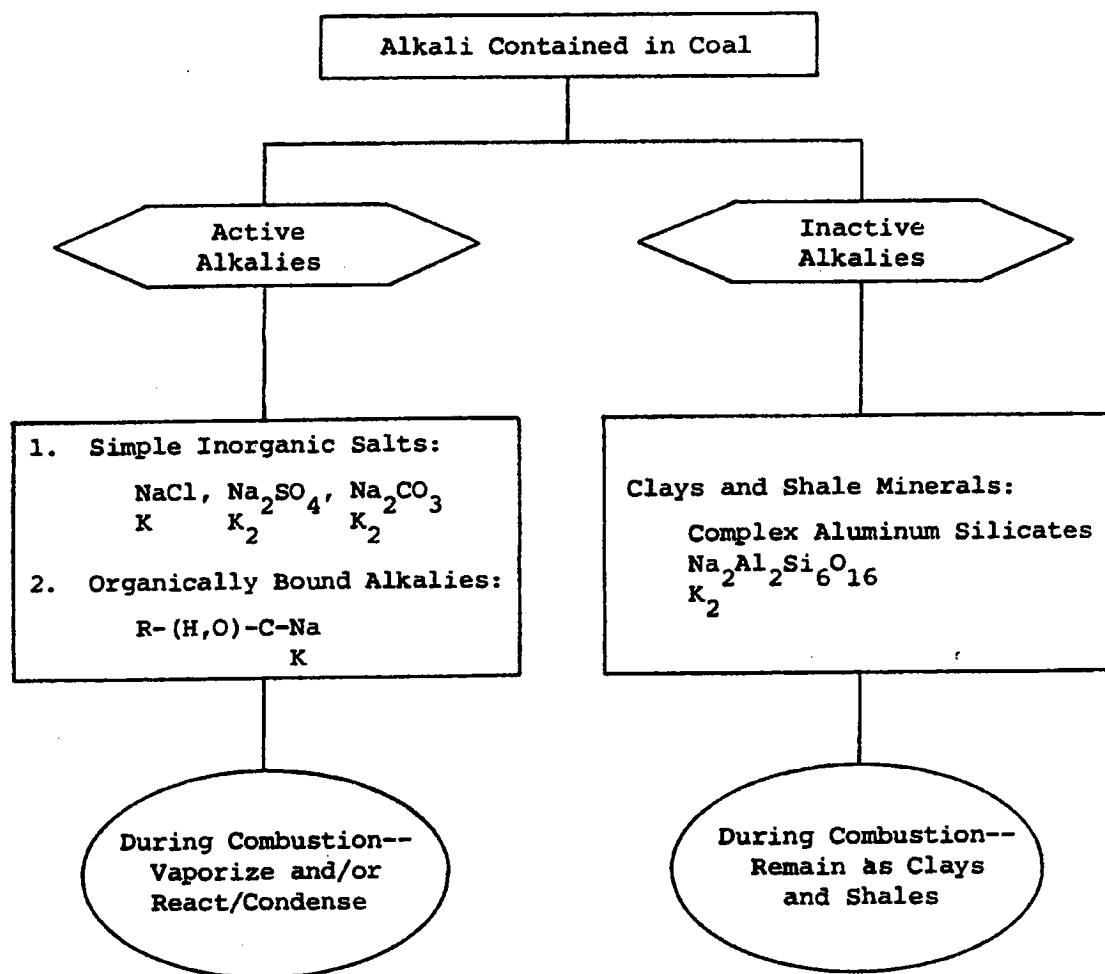


Figure B-2. Manner in which alkalies are contained in coal (Ref. B-16).

B.2.2 Fouling Indices

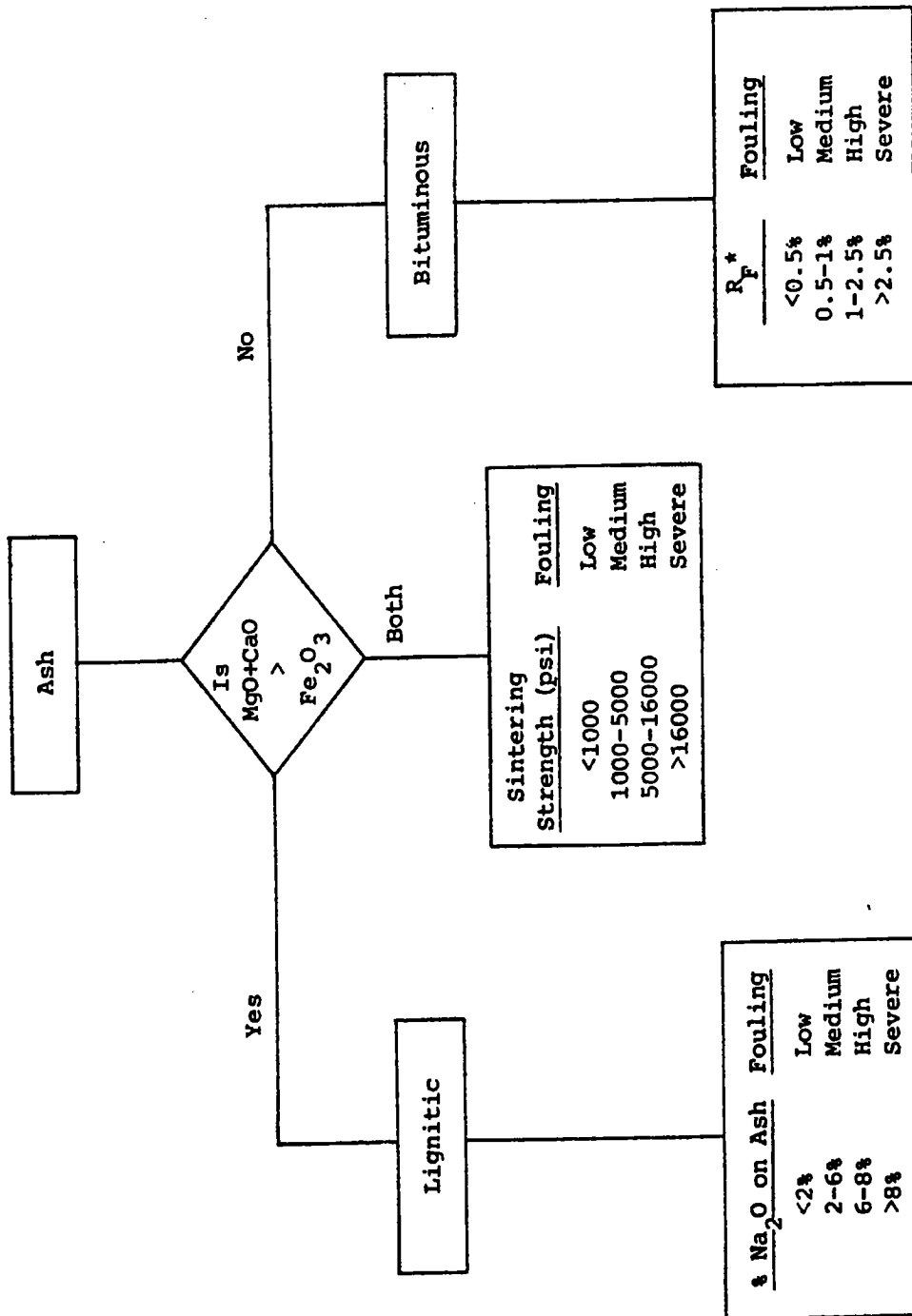
The potential for a coal to foul is related to its ash composition, which is primarily differentiated as being either lignitic or bituminous type ash. The ratio of calcium oxide (CaO) plus magnesium oxide (MgO) to ferric oxide (Fe_2O_3) is the key ratio used to make this differentiation. By definition, ash which has more CaO + MgO than Fe_2O_3 has a lignitic type ash, and ash which has more Fe_2O_3 than CaO + MgO has a bituminous type ash. This distinction is important, as other fouling indices are developed specifically for one or the other of these ash types. Figure B-3 illustrates the fouling potential of each type of coal ash and the indices used to predict them.

TABLE B-1. MELTING POINT OF COMPLEX SULFATES

Compound	Melting Point (°F)
$\text{K}_3\text{Fe}(\text{SO}_4)_3$	1145
$\text{K}_3\text{Al}(\text{SO}_4)_3$	1210
$\text{KFe}(\text{SO}_4)_2$	1281
$\text{Na}_3\text{Fe}(\text{SO}_4)_3$	1155
$\text{Na}_3\text{Al}(\text{SO}_4)_3$	1195
$\text{NaFe}(\text{SO}_4)_3$	1274

The fouling potential of western coal is primarily related to the percent Na_2O in the ash. Fouling potential versus percent Na_2O is shown in Figure B-3.

Experimental laboratory work by Sondreal et al. (Ref. B-18) on low rank western coals has clearly confirmed that fouling is influenced primarily by sodium content in coal, and has shed light on the roles of potassium, calcium, and silicon. Potassium should influence fouling in the same manner as sodium. However, most of the potassium in western coals is bound in clay in small amounts. It does not appreciably influence fouling. Testing with added potassium as organometallic compounds has shown that potassium influences fouling in the same manner as sodium (Ref. B-18). Tests performed by Sondreal et al. also have shown that higher calcium content tended to decrease fouling while high silica content increases fouling.



B-10

*R_F = Base/acid ratio of ash x % Na₂O on Ash

$$\text{Base/Acid} = \frac{\text{FeO}_3 + \text{CaO} + \text{MgO} + \text{Na}_2 + \text{K}_2\text{O}}{\text{TiO}_2 + \text{Al}_2\text{O}_3 + \text{SiO}_2}$$

Figure B-3. Fouling potential (Refs. B-9, B-20, B-21).

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The fouling potentials of eastern coals are also characterized by the percent Na_2O in the ash. However, their fouling potentials are also related to the base/acid ratio of the ash.* The index used to predict fouling potential of eastern coal ash, R_F , is based on the product of the base to acid ratio multiplied by the percent Na_2O in the coal ash. Fouling potential versus R_F values are shown in Figure B-3.

Another parameter that is useful in predicting the fouling potential for either type of coal is ash sintering strength. In this standard procedure, ash samples are sequentially screened and ignited, and then heated in air. After cooling, the compressional strength is measured and is reported as sintering strength. Extensive testing has shown that coals with high fouling potentials tend to produce fly ashes with high sintering strengths (Ref. B-15). Fouling potential versus sintering strength is also shown in Figure B-3.

B.3 SLAGGING

Slagging refers to deposits of molten ash on the furnace water tubes in the radiant section of the boiler.

B.3.1 Slagging Mechanism

Molten or semi-molten ash particles (slag) are transported to the tube surfaces by the gas stream. After deposition, these ash particles chill and possibly solidify on the tube surface. The strength of their attachment to the tube surface depends on the physical shape and temperature of the surface, the direction and force of impact, and the melting characteristics of the ash (Ref. B-20). Major constituents of slag are high melting oxides of alumina, silica, iron, and calcium. These constituents, combined in certain critical proportions, form eutectics which melt at lower temperatures than any of the pure compounds. As the slag layer thickness increases, the inner layer solidifies due to reduced heat flux from the furnace and the temperature of the outer layer eventually exceeds the initial deformation temperature of the fly ash*, forming a molten layer. Further increases in slag layer thickness increase the temperature and reduce the viscosity of the outer layer and the molten material begins to flow.

*The base to acid ratio is the ratio of the total base (the sum of the percentages of Fe_2O_3 , CaO , MgO , K_2O , and Na_2O) to total acid (the sum of the percentages of SiO_2 , TiO_2 , and Al_2O_3) components in the coal. Its lower and upper limits can approach zero and infinity, respectively. It is generally meaningful only in the range of 0.1 to 1.0 (Ref. B-19).

*Initial deformation temperature is the temperature in an operating furnace at which the particles have a slight tendency to stick together (Ref. B-19).

B.3.2 Slagging Indices

Slagging indices are also based on coal ash type. Two broad categories of indices exist, one based on ash fusion temperature and the other based on molten ash viscosity. Figure B-3 summarizes the indices used to predict slagging potential and shows the critical values for each index.

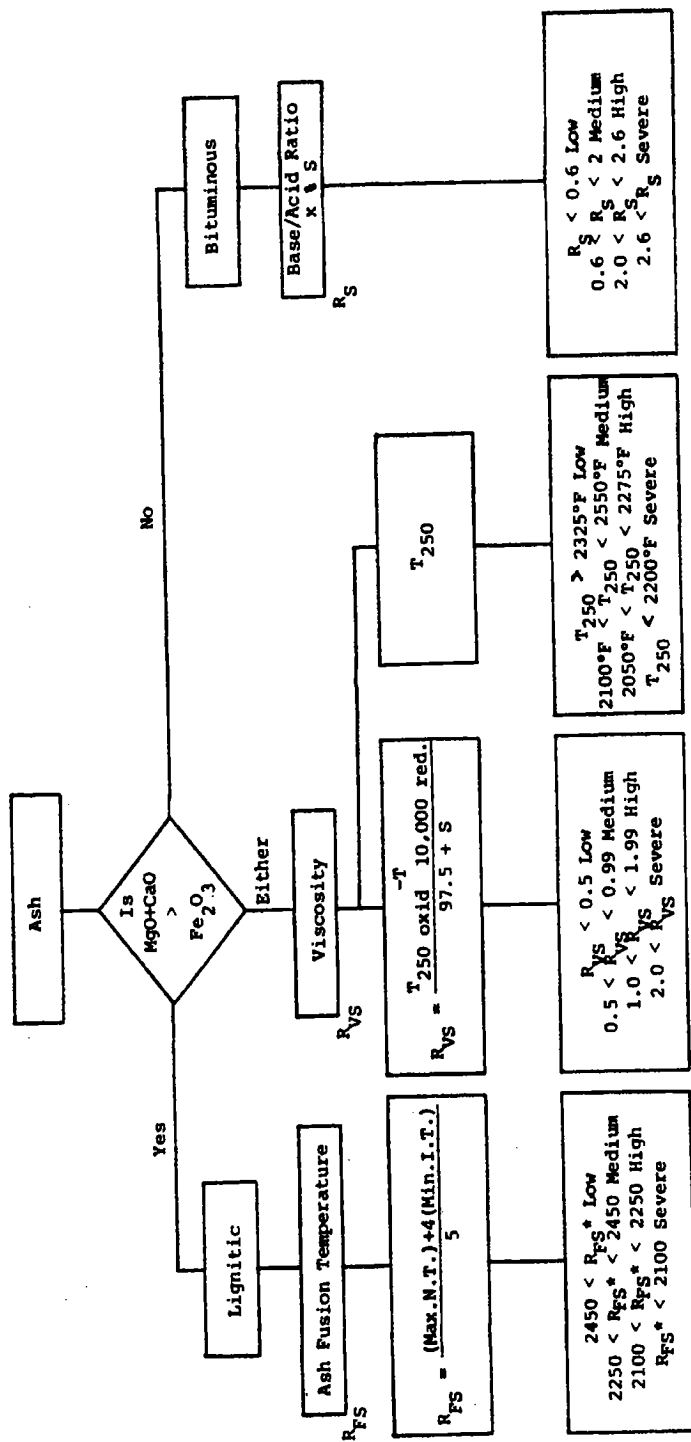
B.3.3 Ash Fusion Temperature

As slagging depends on the existence of molten materials, the ASTM ash fusion temperatures under both oxidizing and reducing conditions have often been used to identify potential problems for various types of coals. Ash fusion temperature can be reported as the initial deformation temperature (I.T.), hemispherical softening temperature (H.T.), spherical softening temperature (S.T.), or fluid temperature (F.T.). Usually, for the purpose of describing the melting characteristics, the hemispherical softening temperature alone is reported.

A regression analysis performed for the ash fusion characteristics of various ranks of coal has indicated a relationship between ash softening temperature and the base/acid ratio of the coal ash (Ref. B-9). This relationship is shown in Figure B-4. The relationship of ash fusion temperature to the base/acid ratio is believed to be due to the influence of fluxing agents. For bituminous coals, the ash is largely acidic, and the fluxing agent is primarily iron. For lignites, the ash is largely basic, and silica and alumina are the primary fluxing agents.

Many ashes have lower ash softening temperatures under reducing conditions than under oxidizing conditions. This is caused by the fluxing action of species such as sulfides formed under reducing conditions. Again, in a lignite-type ash where the iron concentrations are low the effect of a reducing environment on ash fusion temperatures is less than for a bituminous type ash where the iron concentration is high (Ref. B-9). The effects of a reducing environment on these two types of ash are illustrated by Figures B-5 and B-6.

For western coals (lignite-type ash), a fusion slagging index (R_{FS}) based on ash fusion temperatures, has been developed to predict slagging potential. The index considers both the hemispherical softening temperature and the initial deformation temperature. R_{FS} is presented in Figure B-3.



Ash Fusion Temperature:

H.T. = Hemispherical temperature, height = 1/2 width

I.T. = Initial deformation temperature

R_S = Slagging index for bituminous type ash using base/acid of ash ratio and sulfur content of coal.

R_{FS} = Slagging index for lignitic type ash using ash fusion temperature.

R_{VS} = Slagging index using viscosity-temperature characteristic of ash.

T_{250} = Temperature at which the slag viscosity is 250 poise when 20% of the iron in the slag is present in the ferric form.

Figure B-3. Slagging potential (Refs. B-9, B-20, B-21).

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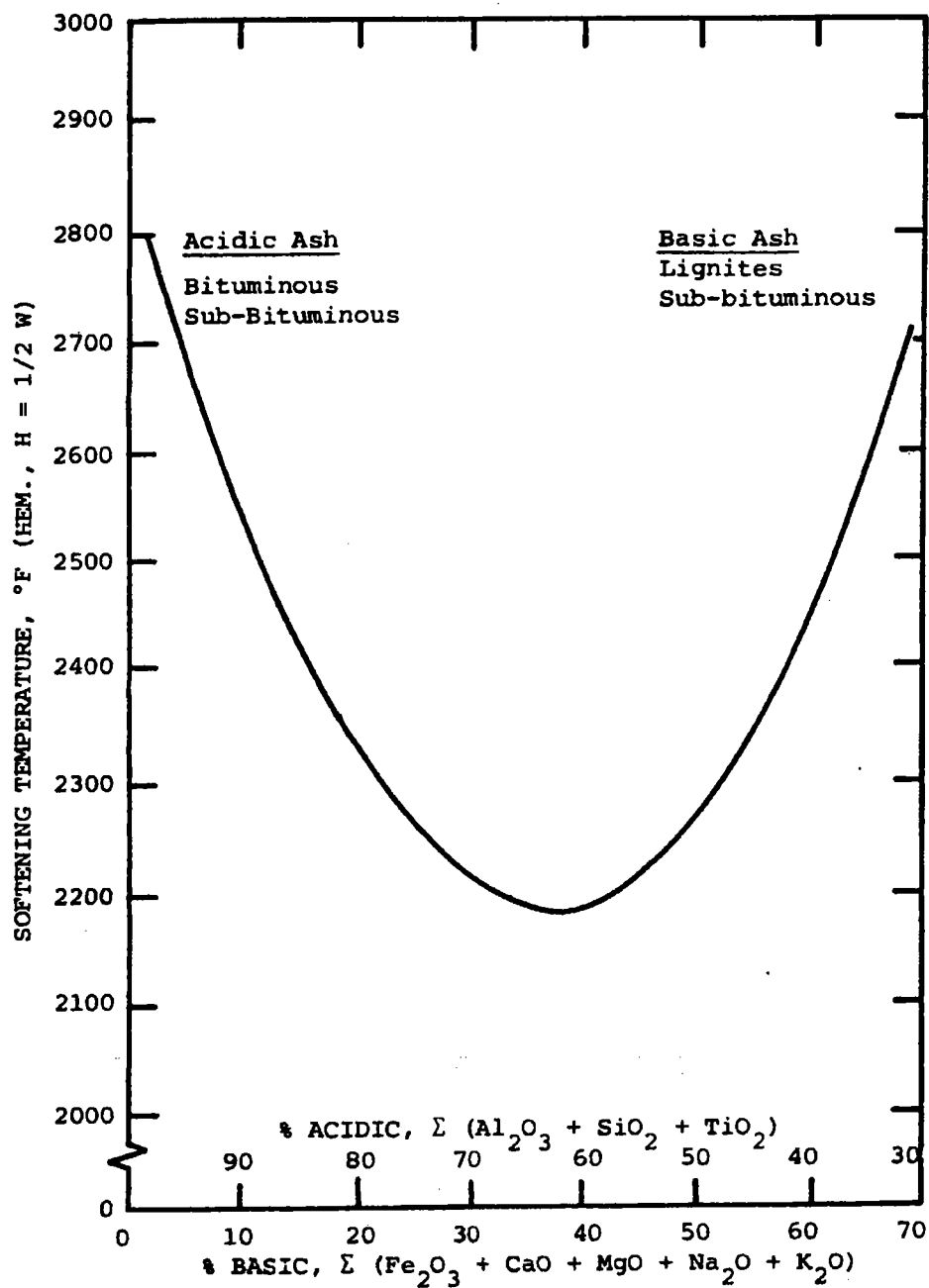


Figure B-4. Typical curve of ash softening temperature vs. basic elements found in the ash (Ref. B-9).

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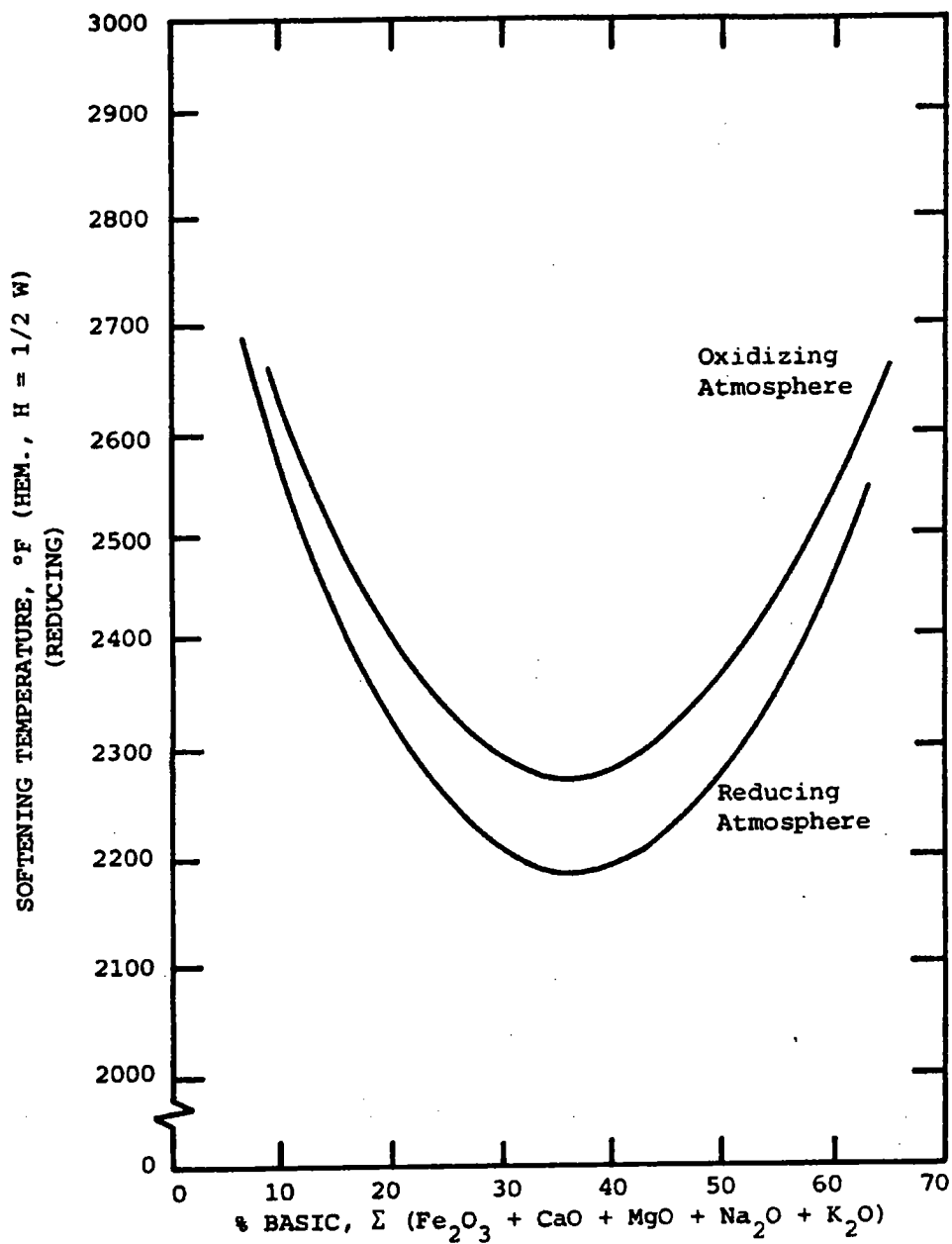


Figure B-5. Comparison of softening temperatures under reducing and oxidizing conditions for various percentages of basic constituents in Wyoming subbituminous coal ash (Ref. B-9).

Also included are the critical values of this index used for predicting slagging potential.

The fusion slagging index developed for eastern coals (bituminous type ash), R_S , is based on the product of the base/acid ratio multiplied by the percent sulfur in the coal. This index, therefore, combines the effect of the base/acid ratio as illustrated by Figure B-4 and also the fluxing action of the sulfides as discussed earlier. Figure B-5 also gives the slagging potential for various values of the R_S index.

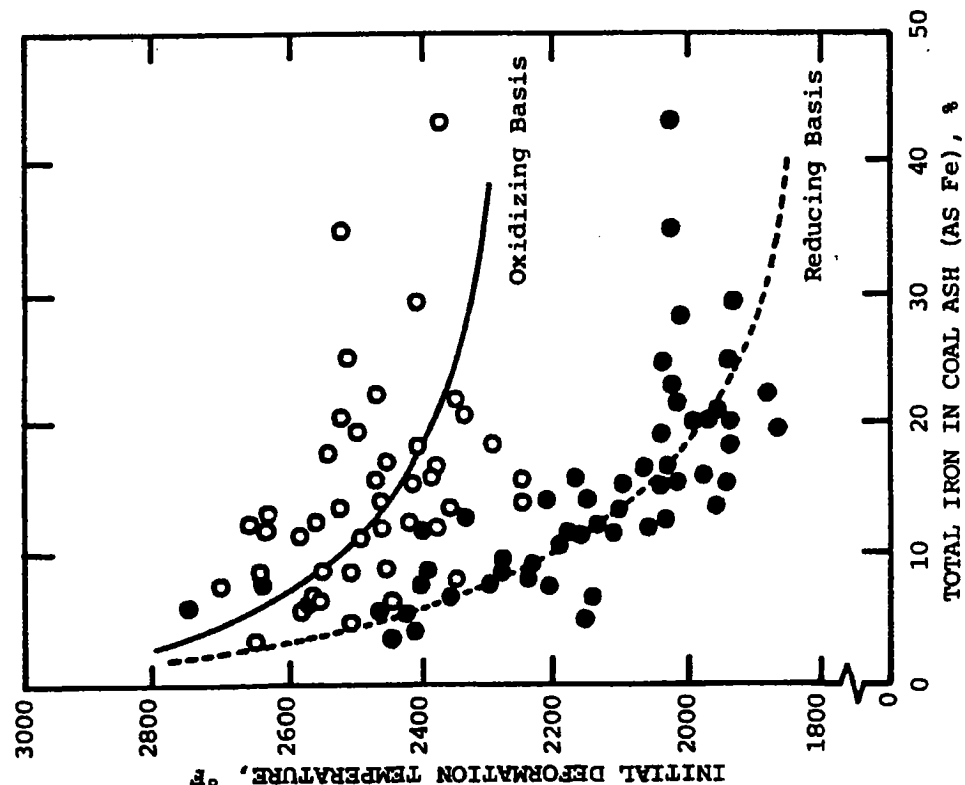
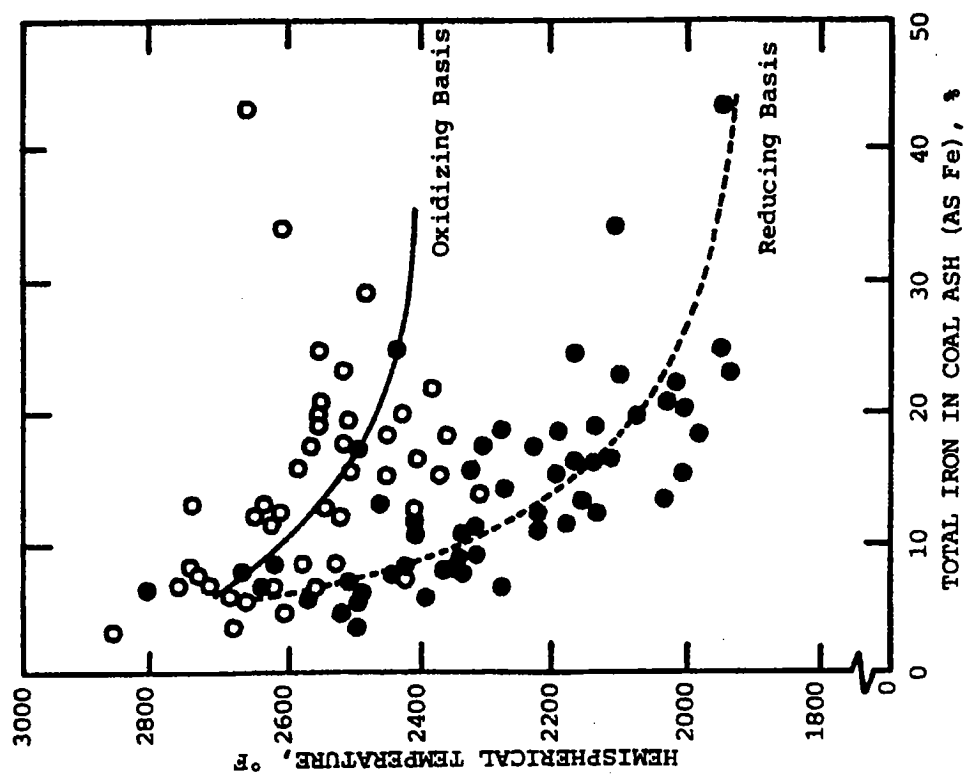
Even though ash fusion temperatures provide a convenient guide to the tendency for a coal to slag, it should be borne in mind that coal ashes are by no means uniform substances characterized by unique softening temperatures. Depending upon its particle sizes and distribution in the coal, the mineral matter in a coal can behave very differently upon entering the furnace.

B.3.4 Ash Viscosity

The viscosity of an ash significantly influences its slagging tendency. At sufficiently high temperatures, all slags flow as Newtonian fluids. Slag is not troublesome as long as it remains a Newtonian fluid or has a viscosity less than 250 poise. Under these conditions, it forms a thin layer of minimal thickness on the furnace tubes which is easily removed (Ref. B-15). The most troublesome slag is plastic slag, which has been arbitrarily defined to exist in the region of 250 to 1,000 poise.

T_{250} , or the temperature at which a slag has a viscosity of 250 poise, has been used to gauge the slagging potential of coal. Three ratios, depending on coal composition, are used to estimate the T_{250} of the slag. The definition of these three indices and the relationship of T_{250} to each is shown in Figure B-7.

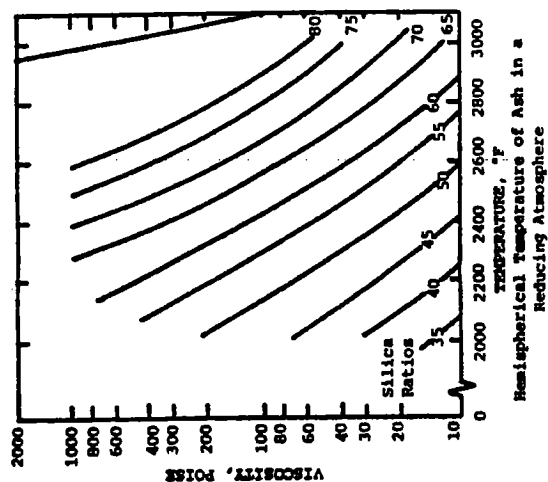
For bituminous type ash, the silica ratio is used in conjunction with the hemispherical softening temperature to calculate T_{250} . For lignitic type ash having an acidic content in excess of 60%, the base to acid ratio is used. The dolomite percentage method is used for coals with lignite type ash and an acidic content less than 60%. Figure B-7 gives slagging potential as a function of T_{250} .



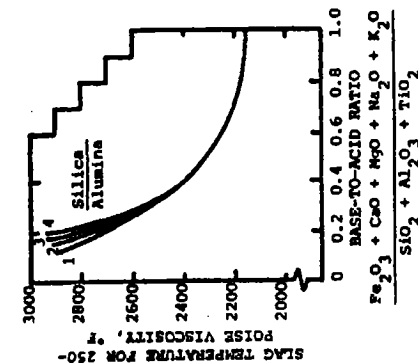
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Figure B-6. Influence of iron on coal ash fusion temperatures (Ref. B-15).

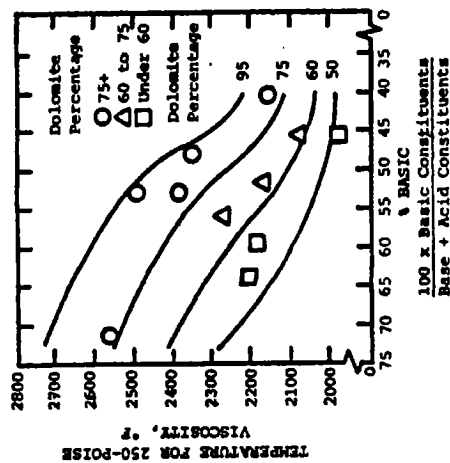
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(a) Silica ratio; used for bituminous-type ash. T_{250} is obtained by entering with the silica ratio and the hemispherical temperature in a reducing atmosphere plus 200°F. For example, for a coal ash having a silica ratio of 62 and a hemispherical temperature of 2300°F, locate this point at the intersection of the 2500°F line and the 62 silica ratio. From this point, extend a straight line at a 10-degree slope from the vertical to the 250-poise value; this slag thus has a calculated T_{250} of 2450°F.



(b) Base-to-acid ratio; used for lignite-type ash having an acidic content in excess of 60%. This correlation takes into account the SiO_2 to Al_2O_3 ratio which has an effect on slags having a low base-to-acid ratio.



(c) Dolomite percentage for coals with lignite-type ash and an acidic content less than 60%. Dolomite percentage =

$$\frac{100 \times \text{Basic Constituents}}{\text{Base} + \text{Acid Constituents}} = \frac{(\text{CaO} + \text{Mg})100}{\text{Fe}_2\text{O}_3 + \text{CaO} + \text{MgO} + \text{Na}_2\text{O} + \text{K}_2\text{O}}$$

Figure B-7. Ratios used to calculate T_{250} (Ref. B-15).

The availability of oxygen in the local environment also affects slag viscosity and the temperature range over which the slag is plastic. Figure B-8 shows the effects on viscosity of changing from an oxidizing to a reducing environment. Flame impingement on furnace walls or low excess air can create a strongly reducing condition and cause severe slagging (Ref. B-15).

The iron content of the ash and the degree of oxidation of the iron also influence the viscosity of the slag. Furnace conditions that delay mixing or are reducing contribute to all of the iron in the coal not being fully oxidized to Fe_2O_3 . Both FeO and Fe are strong fluxing agents and reduce the viscosity of the slag. In addition, these compounds broaden the temperature range over which the slag is plastic (i.e., 250 to 10,000 poise). The parameter used to measure the degree of iron oxidation is the ferric percentage, FP:

$$\text{FP} = [\text{Fe}_2\text{O}_3 / (\text{Fe}_2\text{O}_3 + 1.11 \text{FeO} + 1.43 \text{Fe})] \times 100$$

Figure B-9 shows the effect of ferric percentage on the viscosity of a typical slag. For coals having small amounts of iron, such as a lignite-type ash, this effect will be diminished.

An index based on ash viscosity independent of ash type has been developed to predict slagging potential and is reported to be the most accurate slagging index (Ref. B-22). This index is based on the temperature at which the ash viscosity is 250 poise in an oxidizing environment and the temperature at which the ash viscosity is 10,000 poise in a reducing environment. The index is also based on a correlation factor which is related to the temperatures at which the ash viscosity is 2000 poise in reducing and oxidizing environments. The viscosity factor (R_{VS}) is:

$$R_{VS} = \frac{(T_{250 \text{ oxid.}}) - (T_{10,000 \text{ red.}})}{97.5 f_s}$$

where:

$T_{250 \text{ oxid.}}$ = temperature, F, corresponding to a viscosity of 250 poise in an oxidizing atmosphere.

$T_{10,000 \text{ red.}}$ = temperature, F, corresponding to a viscosity of 10,000 poise in a reducing atmosphere

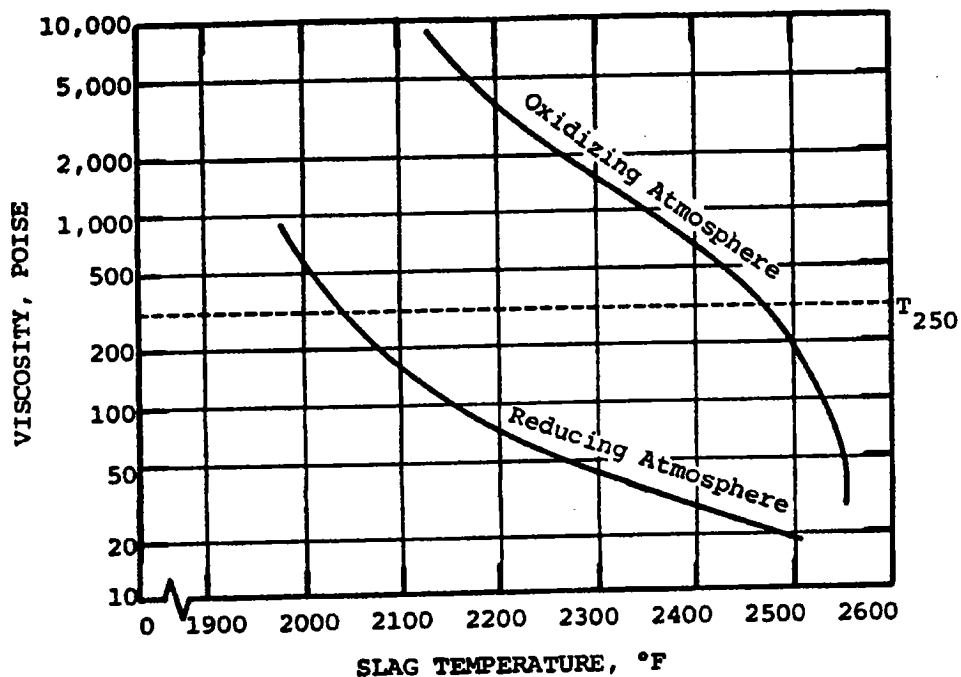


Figure B-8. Viscosity-temperature relationship (Ref. B-15).

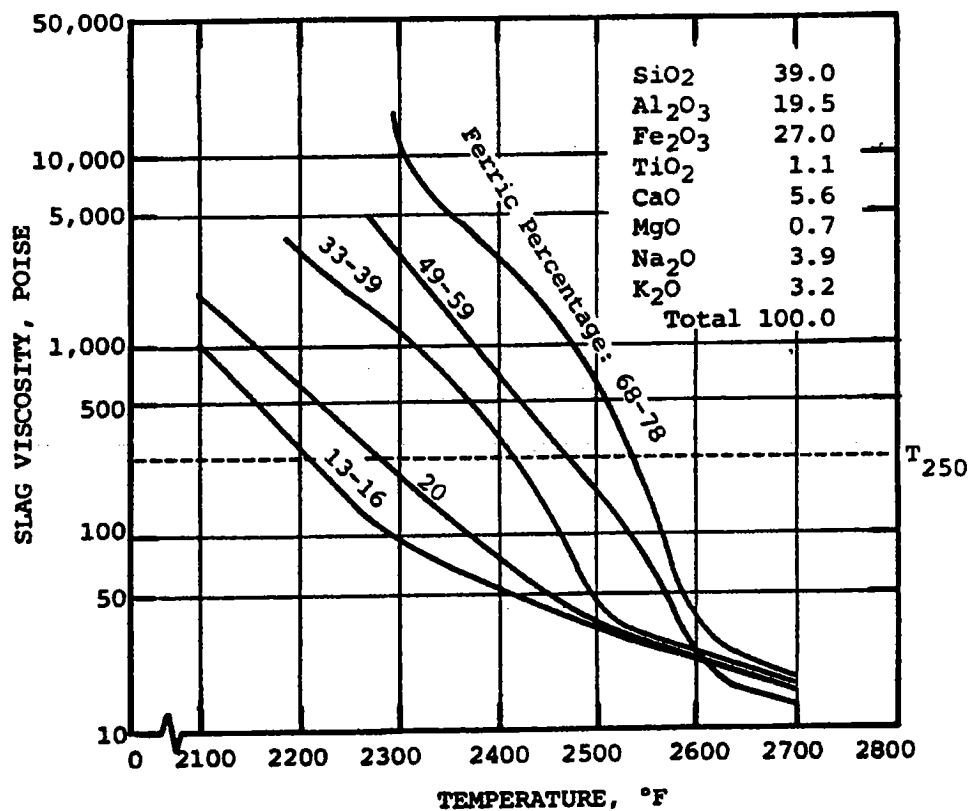


Figure B-9. Viscosity-temperature plots of a typical slag showing effect of ferric percentage (Ref. B-15).

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and f_s is a correlation factor that varies with temperature and can be found by interpolation with the following information:

f_s at 1900°F	=	1.0
f_s at 2000°F	=	1.3
f_s at 2100°F	=	1.6
f_s at 2200°F	=	2.0
f_s at 2300°F	=	2.6
f_s at 2400°F	=	3.3
f_s at 2500°F	=	4.1
f_s at 2600°F	=	5.2
f_s at 2700°F	=	6.6
f_s at 2800°F	=	8.3
f_s at 2900°F	=	11.0

and

$$T_{fs} = \frac{(T_{2000 \text{ oxid}}) + (T_{2000 \text{ red}})}{2}$$

T_{fs} = temperature for f_s calculation

$T_{2000 \text{ oxid. or red.}}$ = temperature, °F, corresponding to a viscosity of 2000 poise in an oxidizing or reducing atmosphere.

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APPENDIX C

SCR-RELATED EXCERPTS FROM STEARNS-ROGER REPORT

The Los Angeles Department of Water and Power recently had Stearns-Roger Engineering Corporation prepare a report (dated April 8, 1983), "Review of the California Air Resources Board Report Titled 'Proposed Guidelines for the Control of Emissions from Coal-Fired Power Plants'". Parts of the Stearns-Roger report addressed the present status of NOx control by SCR. Portions which are relevant in general to plants fired with U.S. coals are quoted below.

Integrated Emission Controls

..."The SCR system requires relatively high temperatures for its operation, which are available upstream of the air preheater. The fabric filter must operate at lower temperatures, available downstream of the air preheater. Therefore, the fabric filter system is downstream of the SCR system. Fine ammonium bisulfate particulate carryover has been experienced with SCR systems. This particulate could effect the fabric filter systems because of bag blinding and shortened bag life..."

EPA Pilot Plant

"EPA constructed and tested an SCR pilot plant supplied by Hitachi Zosen. Only the SCR system was tested; determining impacts on downstream equipment was not in the scope of the EPA work. The pilot plant was located at the Mitchell Station of Georgia Power and utilized flue gases from combusted medium-sulfur eastern coal.

"Relevant results and problem areas that were not resolved in the recently completed test program are:

- . Although the initial catalyst was successfully piloted in Japan on Japanese coals, it required replacement with a more open catalyst to accommodate the U.S. coal tested.
- . Measurable deterioration in catalyst activity occurred in 6 months. Regeneration was required to restore the activity. Catalyst life of 1-year was not confirmed.
- . Ammonia carryover levels were approximately 55 ppm (at 90% NOx removal). SO₃ generation was approximately 12 ppm. Both of these species adversely effect operation of downstream equipment. (The Takahara demonstration reported problems with less than 5 ppm ammonia carryover.)
- . General problems with monitors and controls.

EPDC Takahara Demonstration

"The Japanese have the most experience with SCR processes. However, most of their experience is with oil firing. A Japanese test of SCR processes on a demonstration-scale coal-fired unit was conducted for a year during 1981 and 1982 on Takahara Unit No. 1.

"The Japanese use coals, at least the Takahara Station, which were not from the United States. Australian and South African coals were reported to be in use. As in any coal-fired power plant, the coal fired and its ash are important considerations in the design and operation. Insufficient information is known about the differences between the tested coal and the western U.S. coal tested at the Arapahoe Station. The SCR process, however, appears to have significant performance deviations with different coals. Insufficient test work has been done on different coals to predict performance with any specific non-tested coals. These tests pertained to the air pollution control equipment as well as to the boiler and coal handling equipment.

"Reference 41 briefly reviews the Takahara tests. In addition, the following items must be considered:...

- . On-line air heater washing was cited as a means to control air heater fouling. This operation creates safety problems and shortens air preheater life. In addition, modified sootblowers were required to control air heater fouling.
- . The paper stated that NH_3 monitoring in Japan was still in the research and development stage.
- . Little was stated on the automatic control of the process. The problem being principally the primary elements to monitor NO_x which must provide reliable, accurate, and repeatable NO_x measurements to allow functional automatic control. Extractive NO_x monitoring equipment adds additional complexity to this problem.
- . Adverse affects on downstream air preheaters, fans and FGD wastewater were experienced."

Overview

..."With regard to the experience base for SCR, relevant experience is very limited. This means there is a high risk in applying this technology to a new coal-fired boiler. Relevant experience is limited to two U.S. pilot plants and the Japanese demonstration project at Takahara.

"Even though the 100 MW demonstration at Takahara was preceded by a great deal of pilot test work, much was learned in the demonstration. Specifically, catalyst quantities had to be increased during the demonstration to reduce ammonia slip and its adverse affects on the downstream booster fan and air preheater. Also this SCR is preceded by a hot-side electrostatic precipitator and even though the fly ash content of the flue gas treated by the SCR is very low, dust buildup and blockage of catalyst occurred. Thus even though preceded by extensive pilot work, the initial scale up to 100 MW could not be termed totally successful.

"...At Takahara the SCR system is preceded by a hot-side ESP. In the U.S., hot-side ESP's are generally no longer considered

the collector of choice, having been replaced by the rigid frame ESP or the fabric filter. Disadvantages of the hot-side ESP leading to this situation include high capital cost, mechanical problems due to thermal expansions and distortion, and performance which sometimes tends to deteriorate over a period of time. The performance tends to be very sensitive to the coal characteristics and modification of the ash chemistry by flue gas conditioning is common in the existing U.S. hot-side ESP installations. Because of these and other problems, the U.S. utility industry is tending toward the fabric filter...Thus in the U.S., new installations would tend to not have a hot-side ESP and any SCR device would be subject to the high concentration of fly ash coming directly from the boiler. This is in contrast to the Japanese demonstration where fly ash concentrations are very small. Thus the Japanese demonstration is not relevant to the anticipated application in the U.S.

"The relevance of the Takahara demonstration is...diminished in that the coal burned is not typical of the low sulfur western coals...The chemical and physical properties of coal vary considerably. Resultant properties of the fly ash and flue gas also vary widely, and performance of air pollution control equipment changes dramatically with coal type. In lieu of demonstration firing the coal under consideration, correlations to adjust SCR design for different types of coals are required. Unfortunately the data base to develop these correlations is limited to one western sub-bituminous coal, one eastern U.S. coal, and the foreign coals burned at Takahara. It can be stated with some certainty that the design of the SCR must change significantly with coal type but that correlations needed to accommodate coal types are lacking, due to the small amount of data available. Thus the relevance of the Takahara demonstration is of questionable value for designing for U.S. coals.

"Using the data from the two U.S. pilot plants is also risky. The problems encountered at Takahara in scaling up to 100 MW (under ideal conditions of low fly ash loading) verify this concern..."

Catalyst Poisons

"The Japanese have expressed concern in technical papers about calcium, potassium, and sodium in coal ash and their potential to poison (i.e., deactivate) the catalysts used for SCR systems. Pertaining to catalyst performance drop, one paper⁽²⁶⁾ states, "This poisoning by calcium or similar elements is suggested, making it necessary to check calcium content before applying SCR to power plants." Another paper⁽²⁷⁾ states the following: "Influences of SOx halogen (HC, HF) and alkali metals in dust, especially potassium, on catalytic performances may be anticipated. The decrease of catalytic performance must be especially avoided, because it causes not only the lack of stability of the system but also the increase of running cost. Accordingly, it is necessary to develop catalysts which can resist against the particular properties of coal-fired flue gas." A later article⁽²⁸⁾ states, "Catalyst deactivation also has been studied and KHI has found that potassium compounds such as KCl and K_2SO_4 will poison the catalyst." It can be seen that catalyst poisoning is a genuine concern.

"Test results from the 1 year commercial scale test at Takahara [Unit] 1 in Japan have established a catalyst life of 1 year. This same result was obtained at the Arapahoe Power Plant test facility.

"While limited data is available on the decrease in catalyst performance on either test, both tests confirmed a 1 year catalyst life. The extension of catalyst life beyond 1 year remains an important objective necessary for commercial acceptance. At the present time, a method to project long-term catalyst deterioration has not been developed."

FGD Liquors

..."The impact of NH_3 carryover on fly ash and wastewaters will have to be considered carefully to comply with solid waste disposal regulations and NPDES requirements."

Waste Disposal Complications

..."Landfilling [of some SCR catalysts] presents significant technical problems. The spent catalyst has to be considered a hazardous waste since it may contain compounds such as vanadium pentoxide (V_2O_5)..."

"Waste disposal costs, either by recycling or landfill...are expected to be significant. The unknown catalyst life, hence unknown quantities involved, affect the magnitude of this cost."

Incremental Costs for NOx Control

..."The history of emerging technologies for air pollution control has been that once accepted, the cost of the technology has risen significantly. FGD systems and fabric filters are excellent examples."

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APPENDIX D
COAL ANALYSES

Potential IPP Coals

Typical Australian Coals

Typical South African Coals

TABLE D-1. TYPICAL ANALYSES FOR IPP COALS

	Coal A	Coal B	Coal C	Coal D	Coal E	Coal F	Coal G
Proximate Analysis, As Received, Diluted							
Moisture	8.6	8.3	10.5	9.8	10.6	18.8	6.5
Ash	15.6	14.0	7.2	8.8	9.3	7.9	15.8
Volatile	36.0	37.1	39.4	38.2	35.8	35.5	33.2
Fixed Carbon	39.8	40.6	42.9	43.2	44.3	37.9	44.5
Btu	10,930	11,010	11,577	11,690	9,662	11,205	
Miscellaneous, Undiluted							
Sulfur Form, dry basis							
Pyritic	0.19	0.18	--	0.09	--	--	--
Sulfate	0.00	0.00	--	0.01	0.00	--	--
Organic	0.56	0.37	--	0.49	0.36	--	4.2
Equilibrium Moisture	6.8	6.5	--	5.8	--	--	--
Grindability	46	48	49	47	--	55	44
Fusion Temperature, Undiluted							
Reducing							
I.D.	2300	2180	2140	2335	2160	2250	2330
H=W	2470	2215	2170	2355	2180	2350	2400
H=1/2 W	2515	2245	2195	2380	2195	2380	2475
Fluid	2615	2330	2245	2415	2220	2400	2560
Oxidizing							
I.D.	2420	2240	2205	2395	2190	--	2395
H=W	2560	2300	2230	2415	2210	--	2465
H=1/2 W	2580	2325	2260	2435	2225	--	2525
Fluid	2670	2410	2310	2470	2255	--	2595
Ultimate Analysis, Diluted							
Carbon	59.90	61.45	65.43	66.20	63.66	55.60	63.40
Hydrogen	4.50	4.56	4.88	4.91	4.37	4.13	4.32
Nitrogen	0.93	1.20	1.26	1.31	1.05	0.86	1.17
Chlorine	0.02	0.02	0.01	0.02	0.02	0.04	0.03
Sulfur	0.75	0.55	0.48	0.59	0.44	0.93	0.61
Ash	15.60	14.00	7.20	8.80	9.30	7.81	15.80
Oxygen	9.70	9.92	10.24	8.37	10.56	11.83	8.17
Moisture	8.60	8.30	10.50	9.80	10.60	18.80	6.50
Mineral Analysis, Ignited Basis, Undiluted							
Phos. pentoxide, P_2O_5	0.4	0.3	0.2	0.6	0.2	0.2	0.6
Silica, SiO_2	61.1	58.5	53.6	52.6	51.0	41.7	58.7
Ferric oxide, Fe_2O_3	4.6	5.9	7.1	4.4	5.2	7.0	3.4
Alumina, Al_2O_3	21.6	13.5	13.2	22.8	13.0	26.4	20.7
Titanium, TiO_2	1.1	0.7	0.7	1.0	0.7	1.7	0.8
Lime, CaO	4.6	9.3	12.3	7.8	14.6	6.8	6.6
Magnesia, MgO	1.0	2.0	2.5	1.1	3.0	1.4	1.6
Sulfur trioxide, SO_3	2.9	5.9	8.4	5.5	7.8	10.6	5.3
Potassium oxide, K_2O	1.2	0.9	1.0	0.6	0.6	0.2	0.7
Sodium oxide, Na_2O	1.0	1.6	0.5	2.6	3.1	3.0	0.9
Undetermined	0.5	1.1	0.5	1.0	0.3	1.0	0.7
Free swelling index	--	1.5	--	--	--	0	3
Calculated Values, Diluted Where Applicable							
Lbs Ash/MMBtu	14.3	12.71	6.22	7.53	8.41	8.07	14.10
Base/Acid	0.15	0.27	0.35	0.22	0.41	0.26	0.16
$Na_2O/MMBtu$	0.14	0.20	0.03	0.20	0.26	0.24	0.13
Fe_2O_3	1.00	0.63	0.58	0.56	0.36	1.03	0.52
$SiO_2 + Al_2O_3/MMBtu$	11.83	9.19	4.15	5.68	5.38	5.50	11.20
$Fe_2O_3 + CaO$	9.20	15.20	19.40	12.20	19.80	13.80	10.00
$SiO_2 \times 8$ Ash Dry	0.10	0.09	0.04	0.05	0.05	0.04	0.09
M & A free Btu	14,420	14,172	14,067	14,360	13,310	13,160	14,420
Coal Rank							
Fouling	HiVolB	HiVolC	HiVolC	HiVolC	HiVolC	HiVolC	HiVolB
Slagging	Low	Low	Low	Med	Med	Med	Low
	Med	High	High	Med	High	Med	Med

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TABLE D-2. TYPICAL ANALYSES FOR SOUTH AFRICAN AND AUSTRALIAN COALS

	South African		Australian				
	Coal H	Coal I	Coal J	Coal K	Coal L	Coal M	Coal N
Proximate Analysis, As Received, Diluted							
Moisture	2.9	6.3	7.8	6.1	3.3	4.1	7.3
Ash	13.9	16.6	16.4	25.3	24.7	16.5	26.0
Volatile	28.1	24.5	25.4	24.7	28.3	35.5	31.0
Fixed Carbon	53.1	52.6	50.4	43.9	43.7	43.9	35.7
Btu	11,706	10,987	10,870	9,364	9,828	11,616	9,758
Miscellaneous, Undiluted							
Sulfur Forms, dry basis							
Pyritic							
Sulfate							
Organic							
Equilibrium Moisture							
Grindability	46	50	52	45	50	48	45
Fusion Temperature, Undiluted							
Reducing							
I.D.	2410	2340	2700+	2700+	2700+	2280	2280
H-W	2430	2470	2700+	2700+	2700+	2500	2480
H=1/2 W	--	--	--	--	--	--	--
Fluid	2700	2670	2700+	2700+	2700+	2700+	2700+
Oxidizing							
I.D.	--	--					
H-W	--	--					
H=1/2 W	--	--					
Fluid	--	--					
Ultimate Analysis, Diluted							
Carbon	70.34	63.53	63.22	54.26	57.67	64.47	51.62
Hydrogen	4.07	3.34	3.49	3.29	3.53	4.84	3.67
Nitrogen	1.83	1.23	0.76	1.17	1.08	0.87	0.80
Chlorine	--	--	--	--	--	--	--
Sulfur	0.91	0.77	0.30	0.27	0.50	0.48	0.40
Ash	13.90	16.60	16.40	25.30	24.70	16.50	26.06
Oxygen	5.99	6.30	8.03	9.60	9.22	8.73	10.20
Moisture	2.90	8.17	7.80	6.10	3.30	4.10	7.30
Mineral Analysis, Ignited Basis, Undiluted							
Phos. pentoxide, P_2O_5	1.0	--	0.6	--	0.5	0.5	0.2
Silica, SiO_2	41.5	41.9	55.1	54.9	48.2	56.1	54.5
Ferric oxide, Fe_2O_3	4.8	7.2	6.6	8.8	7.9	3.8	6.7
Alumina, Al_2O_3	30.8	28.4	31.9	30.6	31.6	25.9	24.0
Titania, TiO_2	1.9	1.5	1.3	1.2	1.2	1.1	1.8
Lime, CaO	8.7	7.3	0.7	1.1	3.8	5.0	3.7
Magnesia, MgO	2.2	1.6	0.5	0.8	1.5	2.1	2.3
Sulfur trioxide, SO_3	7.6	7.9	0.1	0.1	2.9	3.2	3.3
Potassium oxide, K_2O	0.3	0.7	1.1	0.8	0.4	0.7	1.0
Sodium oxide, Na_2O	0.2	0.6	0.4	0.5	0.2	0.6	0.3
Undetermined	--	--	--	--	--	--	--
Free swelling index	--	--	--	--	--	--	--
Calculated Values, Diluted Where Applicable							
Lbs Ash/MMBtu	11.87	15.11	15.09	27.02	25.18	14.20	26.64
Base/Acid	0.22	0.24	0.11	0.14	0.17	0.15	0.17
$Na_2O/MMBtu$	0.024	0.09	0.015	0.14	0.05	0.09	0.08
Fe_2O_3	0.59	0.49	9.42	8.0	2.08	0.76	1.81
$SiO_2 + Al_2O_3/MMBtu$	8.58	10.77	13.13	23.1	20.06	11.65	20.92
$Fe_2O_3 + CaO$	13.5	14.5	7.3	9.9	11.7	8.8	10.4
$SiO_2 \times \frac{1}{2}$ Ash Dry	--	--	--	--	--	--	--
M & A free Btu	14,070	14,250	14,340	13,650	13,650	14,630	13,490
Coal Rank	HIVolB	HIVolB	HIVolB	HIVolC	HIVolB	HIVolA	HIVolC
Fouling	Low	Low	Low	Low	Low	Low	Low
Slagging	Low	Med	Low	Low	Low	Med	Med

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APPENDIX E

AUTHOR'S QUALIFICATIONS

J. GEORGE SOTTER

B.S. (with Distinction), Fuel Science - Pennsylvania State University, 1961
Ph.D., Fuel Science - Sheffield University, England, 1964

Dr. Sotter joined KVB shortly after the company's founding in 1970. He was Project Manager in highly successful sulfuric acid fallout reduction projects for 23 boilers in three large California power plants. As part of this work, he invented the first successful method for automatically washing the linings of large chimneys. He has also been involved in efforts to obtain operating permits for new plants, and has contributed air-quality-related studies needed for permits to construct a major new plant. In addition to utility work, Dr. Sotter has solved NO_x, opacity, and other emissions problems for several industrial clients in the western U.S; this included conducting the first full-scale tests of NO_x reduction methods on a large glass furnace.

He was also responsible for establishing KVB's Research and Development Laboratory, and played a significant role in four synthetic fuel development programs for major energy supply companies. Dr. Sotter is co-inventor of two noncatalytic chemical methods for NO_x destruction in utility boilers, and he performed definitive pilot-scale studies of the effects of fuel nitrogen on NO_x formation. This work included extensive testing involving petroleum fuels, shale oil, pyrolytic oils, pulverized coal, and chars produced in coal gasification. He was the first to apply the Thermal DeNO_x method to reducing NO_x emissions from shale oil combustion in pilot-scale tests.

Before joining KVB, Dr. Sotter's work included chemical kinetics analysis and gas turbine development for the AiResearch Manufacturing Company, and liquid propellant combustion studies for the Jet Propulsion Laboratory in Pasadena. Among his major accomplishments was the discovery of the fluid flow mechanism which had caused explosions of numerous rockets over the previous two decades.

His earliest work, for Koppers Company's research center, was on pilot-plant development for fluidized-bed coking of coal and for the manufacture of activated carbon from coal.

Dr. Sotter brought to KVB the unique combination of study in two of the world's most outstanding fuel and combustion schools, and has over 20 years of experience in combustion, including virtually every type of fuel.

Dr. Sotter has published papers in Scientific American and five technical archive journals, as well as in the proceedings of two international symposia. He has been guest lecturer in combustion short courses given for industry by The Pennsylvania State University and the University of California at Berkeley. His professional registration is as a Chemical Engineer, by the states of California and Utah.

PATENT: U.S. 4,208,386

SELECTED

PUBLICATIONS: Reducing Inefficiency and Emissions of Large Steam Generators in the United States," Prog. Energy Comb. Sci.

"Pyrolytic Oil from Tree Bark: Its Production and Combustion Properties," Proc. AIChE 77th Annual Meeting.

"Resonant Combustion in Rockets," Scientific American.

LOWELL L. SMITH

Manager, Western Engineering

B.S., Engineering with Mechanical Option - University of California at Los Angeles, 1961.

Graduate studies in advanced thermodynamics, mathematics and fluid flow at both the University of California at Los Angeles and the University of Southern California.

As Western Engineering Manager, Mr. Smith is responsible for work performed for industrial and utility clients in the western United States. Current major programs being conducted by KVB under his direction include clients such as Southern California Edison Company, Los Angeles Department of Water and Power, Arizona Public Service Company, San Diego Gas and Electric Company, and a number of smaller, industrial programs.

Mr. Smith was previously in charge of the KVB Southern Engineering Office in Houston, Texas, responsible for emission reduction and measurement activities and combustion consulting services in the southern states. Since 1961, he has been performing analytical research and development, design and test activities in the fields of heat transfer, fluid flow, combustion, and aerodynamics since 1962. He has had both supervisory and project responsibility in these areas.

Mr. Smith has been involved with extensive air pollution reduction programs with many utilities in the Southern States. Among these are Houston Lighting and Power, Florida Power and Light, and the Jacksonville Electric Authority. He has been responsible for making recommendations on combustion modifications that would minimize various pollutants from their steam generators. These have included recommendations for equipment modifications to existing units as well as changes in designs of future units. Much of this work with utilities has included extensive test programs designed to define the combustion characteristics that will influence source emissions.

In addition to performing emission reduction programs, Mr. Smith has also assisted various utilities in presenting emission information to air pollution regulatory agencies. Along this line he has been responsible for preparing numerous special studies to assist utilities and other industries in obtaining construction permits where source air pollution was of concern.

Prior to joining KVB, Mr. Smith had been associated with Aerojet General Corporation, TRW Systems, and the University of Southern California Engineering Center. As a Senior Engineering Specialist at Aerojet, Mr. Smith was the manager of a systems analysis department with responsibilities for engineering coordination and design of software associated with a large satellite program. At TRW, Mr. Smith provided technical direction and support in heat transfer and thermodynamic problems relative to combustion devices.

Mr. Smith is the author of a number of technical reports in the area of source air pollution. He has also authored and contributed to papers in the area of utility boiler emission reduction and thermodynamics and heat transfer.

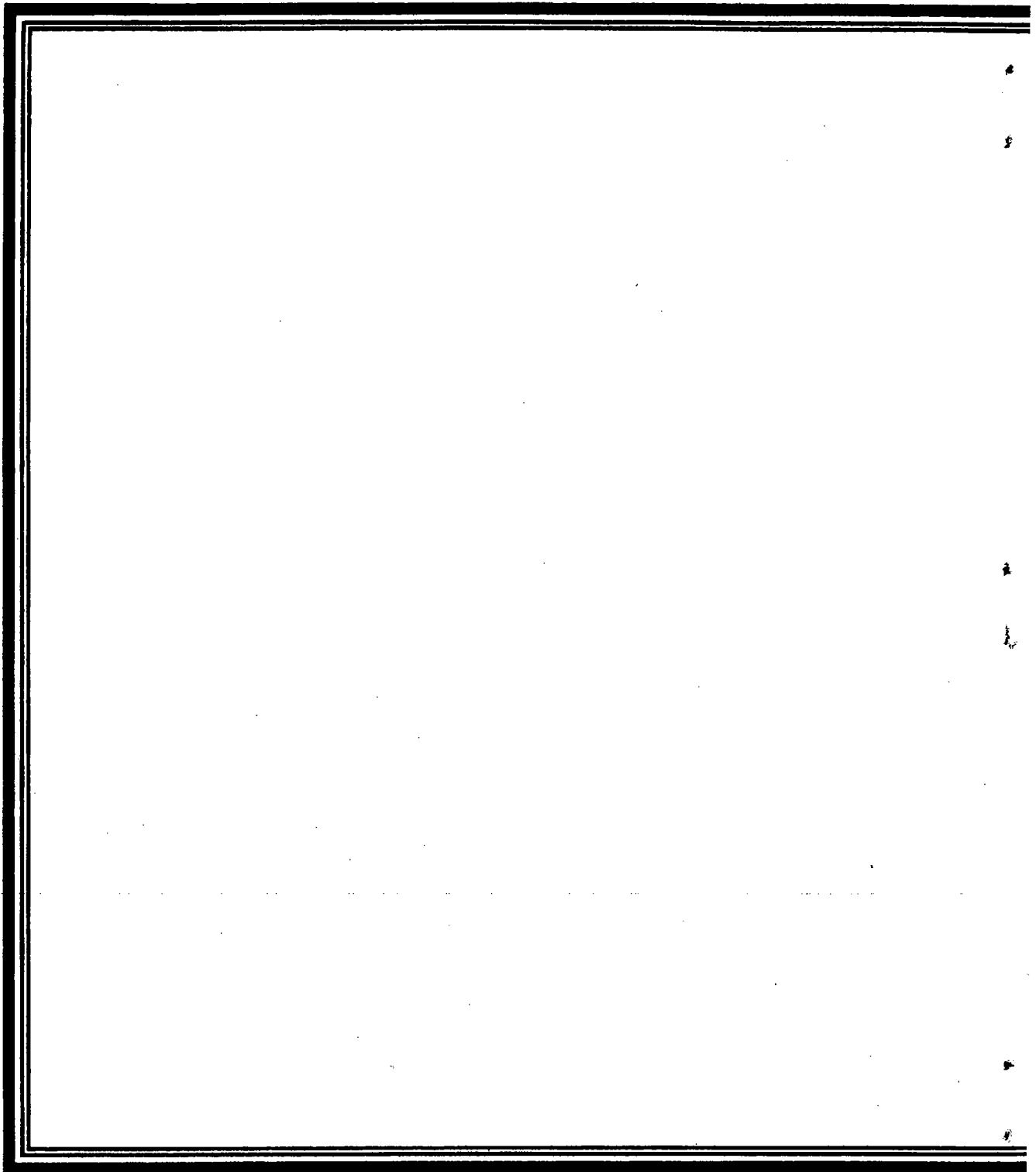
PUBLICATIONS

"Theory and Application of Nitric Oxide Emission Reduction in Utility Boilers," First Annual Symposium on Air Pollution Control in the Southwest, Texas A&M University, November 1973.

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"In-Furnace Control of NO Formation in Gas- and Oil-Fired Utility Boilers," EPA/EPRI Joint Symposium on Stationary Combustion NO_x Control, Dallas, TX, November 1982.



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